STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	**:**	
and	**:**	
The Peoples Light Gas and Coke Company	**:**	**10-0564**
	:	
Petition Pursuant to Section 8-104	**:**	
of the Public Utilities Act to Submit an	**:**	
Energy Efficiency Plan	**:**	

PROPOSED ORDER

January 20, 2011

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I. BACKGROUND AND PROCEDURAL HISTORY

Public Act 96-0033, *inter alia,* added Section 8-104 to the Public Utilities Act ("Act"). 220 ILCS 5/8-104. Section 8-104, Natural gas energy efficiency programs, states that: "It is the policy of the State that natural gas utilities and the Department of Commerce and Economic Opportunity are required to use cost-effective energy efficiency to reduce direct and indirect costs to consumers. It serves the public interest to allow natural gas utilities to recover costs for reasonably and prudently incurred expenses for cost-effective energy efficiency measures."

Section 8-104 "does not apply to a gas utility that on January 1, 2009, provided gas service to fewer than 100,000 customers in Illinois." 220 ILCS 5/8-104(l). Gas utilities serving 100,000 or more customers on January 1, 2009, must file an energy efficiency plan no later than October 1, 2010. ("No later than October 1, 2010, each gas utility shall file an energy efficiency plan with the Commission to meet the energy efficiency standards through May 31, 2014. The Commission shall seek public comment on the utility's plan and shall issue an order approving or disapproving each plan." 220 ILCS 5/8-104(f).)

North Shore Gas Company ("North Shore") serves approximately 158,000 customers in Lake and Cook Counties, Illinois. The Peoples Gas Light and Coke Company ("Peoples Gas") serves approximately 817,000 customers in the City of Chicago. North Shore and Peoples Gas are each wholly-owned subsidiaries of the same parent company, Peoples Energy Corporation. (North Shore and Peoples Gas are together referred to in this Order as the "Utilities," "Petitioners" or the "Utilities.") North Shore and Peoples Gas are each subject to Section 8-104. On September 30, 2010, they filed a Petition seeking approval of their plan for the period June 1, 2011, through May 31, 2014 ("Plan Period").

Section 8-104(h) permits utilities affiliated by virtue of a common parent, as North Shore and Peoples Gas are, to be considered a single utility for purposes of Section 8-104. North Shore and Peoples Gas are not electing treatment as a single utility. They jointly submitted a Plan and supporting testimony given the substantial similarities between the energy efficiency programs that each proposes to offer. Likewise, each utility's proposed cost recovery tariff is substantially the same. NS-PGL Ex. 2.0 at 3.

Section 8-104 also imposes obligations on the Department of Commerce and Economic Opportunity (the "Department" or "DCEO"). Section 8-104(e) further provides that "[t]he details of the measures implemented by the Department shall be submitted by the Department to the Commission in connection with the utility's filing regarding the energy efficiency measures that the utility implements." 220 ILCS 5/8-104(e). The Department initially filed a plan applicable to all gas and electric utilities subject to energy efficiency program requirements on September 30, 2010.[1] That filing was docketed as Docket No. 10-0569. The Department moved to withdraw that filing on October 26, 2010. The Commission granted that motion on November 4, 2010. On December 7, 2010, DCEO filed direct testimony in this proceeding that included its plan as well as certain testimony directed specifically to the Utilities' Plan.

The City of Chicago ("City") filed an appearance in this proceeding. The following filed motions to intervene, each of which the Administrative Law Judge granted: Illinois Attorney General's Office ("AG"); Citizens Utility Board ("CUB"); Environmental Law and Policy Center ("ELPC"); Natural Resources Defense Council ("NRDC"); DCEO; the Illinois Green Economy Network; and The Northern Illinois Municipal Natural Gas Franchise Consortium ("Consortium").

A pre-hearing conference was held on October 29, 2010. An evidentiary hearing at which Petitioners, the Staff and parties had the opportunity to conduct cross-examination of all witnesses occurred on December 20, 2010. The record was marked "Heard and Taken" on December 29, 2010.

The Administrative Law Judge admitted the following evidence into the record: Petitioners' Direct Testimony and Exhibits of Michael Marks (NS-PG Exs. 1.0, 1.1, and 1.2); Direct Testimony and Exhibits of Edward M. Korenchan (NS-PGL Exs. 2.0 REV, 2.1, 2.2, 2.3, 2.4, 2.5, 2.6 REV, and 2.7); Rebuttal Testimony of Michael Marks (NS-PGL Ex. 3.0); Rebuttal Testimony and Exhibit of Edward M. Korenchan (NS-PGL Exs. 4.0 and 4.1). Petitioners also filed the affidavits of Mr. Marks and Mr. Korenchan verifying the testimony and exhibits. Commission Staff's Direct Testimony of David Brightwell (ICC Staff Ex. 1.0) and his affidavit verifying his testimony (ICC Staff Ex. 1.1); Direct Testimony and Exhibits of Richard J. Zuraski (ICC Staff Exs. 2.0, 2.1, 2.2, and 2.3) and his affidavit verifying his testimony and exhibits (ICC Staff Ex. 2.4); Direct Testimony of John Hendrickson (ICC Staff Ex. 3.0) and his affidavit verifying his testimony (ICC Staff Ex. 3.1); and Direct Testimony of Dianna Hathhorn (ICC Staff Ex. 4.0) and her affidavit verifying her testimony (ICC Staff Ex. 4.1). AG's Direct Testimony and Exhibits of Philip H. Mosenthal (AG Exs. 1.0, 1.1, and 1.2). The AG also filed an affidavit of Mr. Mosenthal verifying the testimony and exhibits. CUB-City's Direct Testimony and Exhibit of Christopher C. Thomas (CUB-City Exs. 1.0 and 1.1). CUB-City also filed the affidavit of Mr. Thomas verifying the testimony and exhibit (CUB-City Ex. 1.2). ELPC's Direct Testimony and Exhibits of Geoffrey C. Crandall (ELPC Exs.

[1] Section 8-103 of the Act sets forth energy efficiency program requirements for certain electric utilities. 220 ILCS 5/8-103. Those requirements do not apply to North Shore or Peoples Gas.

1.0, 1.1, 1.2, 1.3, 1.4, and 1.5). ELPC also filed an affidavit of Mr. Crandall verifying the testimony and exhibits. DCEO's Direct Testimony and Exhibits of Jonathan Feipel (DCEO Exs. 1.0, 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6); Direct Testimony and Exhibits of John Cuttica (DCEO Exs. 2.0, 2.1, 2.2, 2.3, 2.4, and 2.5); Direct Testimony and Exhibits of David Baker (DCEO Exs. 3.0, 3.1, 3.2, 3.3, and 3.4); Direct Testimony and Exhibits of Don Fournier (DCEO Exs. 4.0, 4.1, 4.2, 4.3, and 4.4); Direct Testimony and Exhibits of Paul Knight (DCEO Exs. 5.0, 5.1, and 5.2); Direct Testimony and Exhibits of Agnes Mrozowski (DCEO Ex. 6.0); and Direct Testimony of Stefano Galiaso (DCEO Ex. 7.0). DCEO also filed an affidavit for each of its witnesses verifying their testimony and exhibits. Consortium's Direct Testimony and Exhibit of Martin J. Bourke (Consortium Exs. 1.0 and 1.1). The Consortium also filed an affidavit of Mr. Bourke verifying the testimony and exhibit (Consortium Ex. 1.2).

At the December 20, 2010, hearing, the Administrative Law Judge admitted the following cross-exhibits into the record: AG Cross Ex. 1; AG Cross Ex. 2; and ICC Staff Group Ex. 1.

On December 22, 2010, Commission Staff moved for the admission of ICC Staff Group Ex. 2. The Administrative Law Judge granted the Motion on December 29, 2010.

On January 6, 2011, the following filed briefs: North Shore and Peoples Gas; Staff; the AG; CUB and the City; ELPC; DCEO; and the Consortium.

On January 6, 2011, the following filed proposed forms of order: North Shore and Peoples Gas; DCEO and the Consortium.

On January 20, 2011, the Administrative Law Judge issued an Administrative Law Judge's Proposed Order.

On ______________, 2011, the following filed briefs on exception to the Proposed Order: ________________.

II. STATUTORY FILING REQUIREMENTS

Section 8-104(f) of the Act requires that the utility's plan address eight items. Specifically, the law requires that:

> In submitting proposed energy efficiency plans and funding levels to meet the savings goals adopted by this Act the utility shall:
> (1) Demonstrate that its proposed energy efficiency measures will achieve the requirements that are identified in subsection (c) of this Section, as modified by subsection (d) of this Section.
> (2) Present specific proposals to implement new building and appliance standards that have been placed into effect.
> (3) Present estimates of the total amount paid for gas service expressed on a per therm basis associated with the proposed portfolio of measures designed to meet the requirements that are identified in subsection (c) of this Section, as modified by subsection (d) of this Section.
> (4) Coordinate with the Department to present a portfolio of energy efficiency measures proportionate to the share of total annual utility

> revenues in Illinois from households at or below 150% of the poverty level. Such programs shall be targeted to households with incomes at or below 80% of area median income.
>
> (5) Demonstrate that its overall portfolio of energy efficiency measures, not including programs covered by item (4) of this subsection (f), are cost-effective using the total resource cost test and represent a diverse cross section of opportunities for customers of all rate classes to participate in the programs.
>
> (6) Demonstrate that a gas utility affiliated with an electric utility that is required to comply with Section 8-103 of this Act has integrated gas and electric efficiency measures into a single program that reduces program or participant costs and appropriately allocates costs to gas and electric ratepayers. The Department shall integrate all gas and electric programs it delivers in any such utilities' service territories, unless the Department can show that integration is not feasible or appropriate.
>
> (7) Include a proposed cost recovery tariff mechanism to fund the proposed energy efficiency measures and to ensure the recovery of the prudently and reasonably incurred costs of Commission-approved programs.
>
> (8) Provide for quarterly status reports tracking implementation of and expenditures for the utility's portfolio of measures and the Department's portfolio of measures, an annual independent review, and a full independent evaluation of the 3-year results of the performance and the cost-effectiveness of the utility's and Department's portfolios of measures and broader net program impacts and, to the extent practical, for adjustment of the measures on a going forward basis as a result of the evaluations. The resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given 3-year period.

220 ILCS 5/8-104(f). Subsection (f)(6) does not apply to North Shore and Peoples Gas as neither is affiliated with an Illinois electric utility required to comply with Section 8-103 of the Act. However, there is testimony related to the Utilities' offering of certain programs in conjunction with Commonwealth Edison Company ("ComEd") and other coordination between the Utilities and ComEd.

III. NORTH SHORE'S AND PEOPLES GAS' ENERGY EFFICIENCY PLAN

A. Savings Goals

Section 8-104(f)(1) requires the Utilities to show that each of their proposed energy efficiency measures will achieve the requirements identified in subsection (c), as modified by subsection (d). Contested issues related to the Utilities' proposal to meet these requirements are whether their calculations of the savings levels comply with the Act; whether their calculations of the rate impact budget cap comply with the Act; and whether the Commission should require the Utilities to spend additional amounts.

1. Statutory Provisions

Section 8-104(c) establishes the savings requirements applicable to the Utilities. It states, in relevant part, that:

> Natural gas utilities shall implement cost-effective energy efficiency measures to meet at least the following natural gas savings requirements, which shall be based upon the total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section, during calendar year 2009 multiplied by the applicable percentage. Natural gas utilities may comply with this Section by meeting the annual incremental savings goal in the applicable year or by showing that total savings associated with measures implemented after May 31, 2011 were equal to the sum of each annual incremental savings requirement from May 31, 2011 through the end of the applicable year:
>
> (1) 0.2% by May 31, 2012;
>
> (2) an additional 0.4% by May 31, 2013, increasing total savings to .6%;
>
> (3) an additional 0.6% by May 31, 2014, increasing total savings to 1.2%;

220 ILCS 5/8-104(c).

Section 8-104(c) goes on to state the savings applicable to subsequent periods. This proceeding is limited to the first plan period, which is the three-year period of June 1, 2011, through May 31, 2014. Subsection (f)(1) references certain modifications, contained in subsection (d), to the subsection (c) requirements. Those modifications are:

> Notwithstanding the requirements of subsection (c) of this Section, a natural gas utility shall limit the amount of energy efficiency implemented in any 3-year reporting period established by subsection (f) of Section 8-104 of this Act, by an amount necessary to limit the estimated average increase in the amounts paid by retail customers in connection with natural gas service to no more than 2% in the applicable 3-year reporting period. The energy savings requirements in subsection (c) of this Section may be reduced by the Commission for the subject plan, if the utility demonstrates by substantial evidence that it is highly unlikely that the requirements could be achieved without exceeding the applicable spending limits in any 3-year reporting period.

220 ILCS 5/8-104(d).

None of the Utilities, Staff or interveners claim that the Utilities will be unable to meet the subsection (c) requirements for the Plan Period without exceeding the rate impact cap. Thus, the Commission need not address under subsection (d) whether it is necessary to reduce the energy savings requirements. However, the Utilities' calculation of the rate impact cap is at issue as is whether the Utilities should spend up to that cap.

2. North Shore/Peoples Gas' Proposed Programs

Utilities' witness Mr. Marks states that the Plan's overriding objectives are to achieve the annual savings goals as cost effectively as possible and to provide programs to residential and commercial and industrial ("C&I") customers at approximately the same proportion as the revenues each sector contributes to the customer base. Additional objectives are that the Plan:

- is cost effective at the measure, program and portfolio levels;
- uses multiple implementation approaches to maximize program participation and minimize program administrative and delivery costs;
- is easy to modify and adapt to changing market conditions;
- is scalable to ramp up or down as markets, technologies, and opportunities evolve;
- offers diverse program offerings making energy efficiency opportunities available to all customer classes; and
- represents a cost-effective mix of programs aimed at ensuring overall portfolio success.

NS-PGL Ex. 1.0 at 4-5.

Tables 4A and 4B and Section 3.8 of the Plan show in detail how each utility will meet the savings levels applicable to the Utilities. NS-PGL Ex. 1.2 at 9-10 and 41-90. Mr. Marks testifies and the Plan shows that the Utilities are proposing four programs for residential customers and four programs for C&I customers.

The four residential programs are:

- Residential Prescriptive Rebate Program, which would provide residential customers incentives to install measures that improve the heating efficiency of the premises. The program is targeted to two types of customers with gas heating: homes with individual heating systems and individually metered residences; and large multifamily buildings with a central heating system and central meter. The Utilities plan to launch the program June 1, 2011. NS-PGL Ex. 1.2 at 44-50.
- Residential Home Energy Reports, which would provide single family homeowners with consistent feedback on their energy use, comparisons to similar homes in their neighborhood, and targeted tips to achieve energy savings. The program is available to all residential customers, but it is targeted to single family homes in the high-impact savings segments (high gas users). The Utilities plan to launch the program June 1, 2012. NS-PGL Ex. 1.2 at 51-54.
- Residential Multifamily Direct Install Program, which has the objective of securing energy savings by installing low cost hot water and space heating savings

measures. The program is targeted to residential customers who live in multifamily buildings and multifamily building owners and property managers. The Utilities plan to launch the program June 1, 2011. NS-PGL Ex. 1.2 at 55-59.

- Residential Whole House Retrofit Program, which is a placeholder for possible participation in an Illinois Home Performance with Energy Star pilot program. It would be targeted to single family homes heated with gas. The Utilities anticipate launching the program June 1, 2013. NS-PGL Ex. 1.2 at 60-64.

The four C&I programs are:

- C&I Prescriptive Rebates Program, which would encourage the installation of higher efficiency equipment and would provide incentives for installing, replacing or retrofitting qualifying equipment. The program is targeted to C&I customers, particularly smaller use customers. The Utilities plan to launch the program June 1, 2011. NS-PGL Ex. 1.2 at 65-73.
- C&I Custom Rebates Program, which would provide C&I customers with rebate incentives for the installation of gas-related efficiency improvements that are not specified for a prescriptive rebate. The program is targeted to C&I customers with projects not specified under the C&I Prescriptive Rebates Program. It is available to existing and new construction markets. The Utilities plan to launch the program June 1, 2011. NS-PGL Ex. 1.2 at 74-78.
- C&I Retro-Commissioning Program, which is a program to conduct tests to ensure that systems operate as designed and optimize system operations in the context of how buildings are currently used. It is targeted to large C&I customers. The Utilities plan to launch the program June 1, 2011. NS-PGL Ex. 1.2 at 79-83.
- Small Business Efficiency Program, which is an assortment of measures targeted to smaller C&I customers and may include direct installation of low cost measures and energy audits. The Utilities plan to launch the program June 1, 2011. NS-PGL Ex. 1.2 at 84-90.

Mr. Marks states that the Utilities developed their Plan so that all programs will be coordinated with ComEd program offerings to the greatest extent reasonable. Specifically, he states that:

- Residential and C&I Prescriptive Programs: The Utilities will look for joint measures that can benefit both the gas and electric energy use.
- Residential Home Energy Reports Program: The Utilities will look for vendors that have the capability to combine gas and electric in their product offering.
- Residential Multifamily Direct Install Program; Residential Whole-House Retrofit Program; C&I Retro-Commissioning Program; and Small Business Efficiency Program: The Utilities and ComEd intend to offer these programs jointly.
- C&I Custom Rebates Program: The Utilities and ComEd will coordinate their efforts when possible to provide a comprehensive service to customers.

Mr. Marks testified that the Utilities developed the North Shore and Peoples Gas portfolios independently based upon the unique characteristics of each service area. While the Plan has the same eight programs for each utility, those programs have specific features that best support each utility's customers. For example, he explains that, in the Residential Prescriptive Rebate Program, heating system rebates are higher for Peoples Gas than North Shore based on the experience in the Chicagoland Program and trade ally discussions. (Mr. Marks explains that the "Chicagoland Program" is the energy efficiency program currently available in the Utilities' service territories.) NS-PGL Ex. 1.0 at 5-6.

The Utilities contend that neither Staff nor interveners oppose any of the programs or question their inclusion in the Plan.

B. Commission Analysis and Conclusions

The Commission finds that the Utilities' proposed programs meet the requirements of Section 8-104 of the Act.

IV. DETERMINING REQUIRED SAVINGS

A. North Shore/Peoples Gas' Position

1. Exclusions

The starting point for determining the required savings is calendar 2009 deliveries to retail customers. Utilities' witness Mr. Korenchan shows that such deliveries were 248,678,312 therms for North Shore and 1,139,309,191 therms for Peoples Gas. NS-PGL Ex. 2.0 REV at 15. Each of the Utilities must, subject to certain exceptions, achieve savings equal to 80% of the required savings. DCEO is responsible for the remaining 20%. Mr. Korenchan testifies that the applicable savings (in therms) are:

	Peoples Gas	**DCEO**	**Total**
Program Year 1	1,822,894	455,724	2,278,618
Program Year 2	3,645,790	911,447	4,557,237
Program Year 3	5,468,684	1,367,171	6,835,855
	North Shore	**DCEO**	**Total**
Program Year 1	397,886	99,471	497,357
Program Year 2	795,771	198,943	994,714
Program Year 3	1,193,657	298,414	1,492,071

Id.; *also see* NS-PGL Ex. 2.5.

"Program Year" refers to the twelve-month period beginning June 1 and Program Year 1 is June 1, 2011, through May 31, 2012. NS-PGL Ex. 1.2 at 9. Although the

Utilities calculated the savings levels by Program Year, they state that they do not need to achieve the savings each year as long as they achieve the required 1.2% savings during the Plan Period. In support, they cite Section 8-104(c)[2], which they say permits gas utilities to meet targets by year or by Plan Period. Their Plan is to meet the targets by year.

Mr. Korenchan states that the retail customer deliveries that he used exclude deliveries to customers subject to subsection (m) and large volume transportation customers who purchase their supply in the wholesale market. The Utilities state that both exclusions are based on Section 8-104. The relevant language in subsection (c) is "based upon the total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section, during calendar year 2009." Excluding customers meeting the subsection (m) criteria is not in dispute.

According to the Utilities, excluding large volume transportation customer deliveries is required by the words "retail customers." Neither Section 8-104, nor other sections of the Act applicable to gas utilities, define "retail customers." The Utilities state that, absent such a definition under Section 8-104 and given that the General Assembly defined the obligation in terms of retail customer deliveries (and not just "customer," which they state would unambiguously mean all utility service customers), it is reasonable to conclude that "retail" in Section 8-104 exists to distinguish among customers that the utility serves. The Utilities state that it is reasonable and appropriate to look to legislative history and the laws defining the Commission's jurisdiction over non-utility suppliers to help ascertain what "retail" may mean in Section 8-104. The Utilities cite in support:

> "The principles informing statutory construction are familiar. The primary rule of statutory construction is to ascertain and give effect to the legislature's true intent and meaning. [citation omitted]. The language of the statute is the best indication of legislative intent, and our inquiry appropriately begins with the words used by the legislature. [citation omitted]. If the statutory language is clear and unambiguous, then there is no need to resort to other aids of construction. [citation omitted]. However, when the language used is susceptible to more than one equally reasonable interpretation, the court may look to additional sources to determine the legislature's intent. [citation omitted]. All provisions of a statutory enactment are viewed as a whole. [citation omitted]. Accordingly, all words and phrases must be interpreted in light of other relevant provisions of the statute and must not be construed in isolation. [citation omitted]. *Each word, clause and sentence of the statute, if possible, must be given reasonable meaning and not rendered superfluous.* [citation omitted]." (emphasis added) Brucker v. Merola, 227 Ill.2d 502, 513-514.

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[2] "Natural gas utilities may comply with this Section by meeting the annual incremental savings goal in the applicable year or by showing that total savings associated with measures implemented after May 31, 2011 were equal to the sum of each annual incremental savings requirement from May 31, 2011 through the end of the applicable year." 220 ILCS 5/8-104(c).

They state that it is permissible to consider legislative history in this context because "retail customer," as used in Section 8-104, is not unambiguous. *Id*.; *also see*, People v. Collins, 214 Ill.2d 206, 214 ("Where statutory language is ambiguous, however, we may consider other extrinsic aids for construction, such as legislative history and transcripts of legislative debates, to resolve the ambiguity.").

According to the Utilities, the key question is whether distinguishing between sales and transportation customers and also distinguishing between types of transportation customers is appropriate in construing the term "retail customers" in Section 8-104. Illinois law draws distinctions by customer usage between gas customers who purchase supply from non-utility suppliers. The Utilities state that the General Assembly sought to make similar distinctions in Section 8-104. They cite the House of Representatives' debates, during which a sponsor of the bill that included Section 8-104 explains that, in calculating charges, gas purchased at wholesale and only transported by the utility would be excluded. Gas purchased at retail from certified alternative gas suppliers and transported by the utility would be included. NS-PGL Ex. 2.7; *also see* NS-PGL Ex. 2.0 at 15-16. They described the distinction between "wholesale" and "retail":

> Reitz: "… On the gas efficiency provisions, I'd like to make sure I understand how the charges to customers will be calculated. There are some customers, such as merchant electric generators, who purchase all or part of their gas at wholesale and then transport that gas over the distribution system of the local gas utility. When the utility is calculating the charge to customers, will the utility include the cost of the gas that is purchased by the user at wholesale?"
>
> Flider: "No."
>
> Reitz: So, what is excluded is the wholesale commodity cost, the utilities cost for transportation for that wholesale commodity is included, right?
>
> Flider: That's correct, yes.
>
> Reitz: And you were talking about excluding only wholesale commodity purchases, retail gas purchases from public utilities, and certified alternative gas suppliers are included, right?
>
> Flider: Yes.

NS-PGL Ex. 2.7.

The Utilities' proposal includes as "gas delivered to retail customers" all gas sold and delivered to customers in calendar 2009 under its Commission-approved tariffs and all gas they delivered to customers taking services under their small volume transportation customer programs. For the Utilities, the distinction between "wholesale" and "retail" embodied in the debate is well-represented by the two transportation programs they offer. Suppliers serving customers in the small volume program are generally certified alternative gas suppliers. Mr. Korenchan testifies that suppliers serving customers in the large volume program generally need not be certified. NS-PGL Ex. 2.0 at 16.

The Utilities contend that the demarcation between the two programs is a very good, albeit not a perfect, proxy. The criterion requiring an alternative gas supplier to receive Commission certification is that the supplier wishes to serve small commercial customers, which means non-residential retail customers having annual gas consumption of 5,000 therms or less, or residential customers. 220 ILCS 5/19-105, 19-110. Eligibility for the Utilities' programs is based on service classification and not annual consumption. Only the small volume program is open to residential customers. It is also open to Service Classification ("S.C.") No. 2 customers, which includes small commercial customers. The large volume program is not open to residential customers, and a supplier would need to be certified only if it served small commercial customers under that program. *See* Riders CFY, FST and SST of each of the Utilities' Schedule of Rates for Gas Service on file with the Commission.[3]

The Utilities note that certification requirements for gas and electric utilities are different. The Electric Service Customer Choice and Rate Relief Law of 1997 (220 ILCS 5/16-101 *et seq*.) defines "retail customers." Among other things, this law requires all alternative retail electric suppliers ("ARES") to receive Commission certification. By contrast, the Alternative Gas Supplier Law (220 ILCS 5/19-100 *et seq*.) (the "AGS Law") does not define "retail customers" and applies to a smaller universe of customers. Only alternative suppliers wishing to serve residential and small commercial customers must receive Commission certification.[4] The Utilities contend that the exchange between Representatives Reitz and Flider makes sense in the context of the distinctions that the General Assembly had previously made for alternative suppliers in the gas markets.

The Utilities agree with AG witness Mr. Mosenthal that the standard definition of "wholesale" would mean a customer who is not the ultimate end user. AG Ex. 1.0 at 11. However, they state that Representatives Reitz's and Flider's exchange showed that they were using the term "wholesale" differently. The AGS Law clearly distinguishes between small and large gas users in determining regulation of non-utility suppliers. Consequently, the Utilities state that, contrary to Mr. Mosenthal's conclusion that "just being larger" does not make a customer "wholesale" (AG Ex. 1.0 at 11), Representatives Reitz and Flider made that distinction.

Although the Utilities disagree that large volume transportation customer deliveries should be included to compute the savings requirements, Mr. Korenchan agrees that the data Mr. Zuraski presents are accurate if the Commission adopts an alternative legal interpretation. NS-PGL Ex. 4.0 at 4; *see* ICC Staff Ex. 2.2. Mr. Korenchan states that Mr. Mosenthal's calculation is grossly overstated and actually results in deliveries that are double what the Utilities actually delivered in 2009. NS-

[3] The Commission may take administrative notice of "Annual reports, tariffs, classifications and schedules regularly established by or filed with the Commission as required or authorized by law or by an order or rule of the Commission." 83 Ill. Admin. Code §200.640(a)(3).

[4] "The provisions of this Section shall apply only to alternative gas suppliers serving or seeking to serve residential or small commercial customers and only to the extent such alternative gas suppliers provide services to residential or small commercial customers." 220 ILCS 5/19-110(a), Certification of Alternative Gas Suppliers.

PGL Ex. 4.0 at 4. If the Commission adopts the alternative interpretation of "retail customers," then the Utilities request that the Commission approve the data in Mr. Zuraski's exhibit and reject Mr. Mosenthal's calculations.

2. Rate Impact Budget Cap

A utility must limit the measures implemented in any three-year planning period as needed to limit the average increase for gas service to retail customers to no more than 2% for the period. 220 ILCS 5/8-104(d). The Utilities state that this limit should not affect their ability to meet their portion of the statutory goals for the Plan Period.[5] They base their cap calculations on estimated amounts for the first Program Year. Mr. Korenchan states that the statutory caps for the Plan Period are $27,113,945 for Peoples Gas and $5,354,246 for North Shore. The Utilities' estimated rate impact of implementing the proposed measures is within the statutory cap. NS-PGL Ex. 2.0 REV at 16-17; NS-PGL Ex. 2.6 REV.

The Utilities note that Mr. Zuraski's calculation of the cap is identical to the Utilities' calculation. ICC Staff Ex. 2.2. This calculation apparently accepts the Utilities' exclusion of revenues associated with gas sold by non-utility suppliers to large volume transportation customers. (Mr. Mosenthal disagrees with this exclusion. The Utilities state that, for the same reasons that large volume transportation customer deliveries should be excluded from computing the savings requirements, it is proper to exclude these revenues.) However, the Utilities state that Mr. Zuraski's alternative approach would create the conundrum under which the large volume transportation deliveries are included for purposes of calculating the savings targets, *i.e*., increasing the target, but excluded for purposes of calculating the funding available to meet the savings targets, *i.e*., reducing available funding. The Utilities' interpretation of Section 8-104 treats large volume transportation customers' deliveries and revenues consistently and does not, by virtue of inconsistent treatment, result in fewer funds to meet larger targets.

The Utilities state that their calculation of the rate impact cap is accurate and consistent with Section 8-104 of the Act, as bolstered by the legislative history addressing this issue.

3. Spending Levels

The Utilities responded to Mr. Crandall's statements that North Shore and Peoples Gas may fall short of the statutory goals and describes their Plan as having "little room for error." ELPC Ex. 1.0 at 7-8. He also questions DCEO's ability to meet its 20% savings levels. ELPC Ex. 1.0 at 7-9. Finally, he recommends that the Commission direct North Shore and Peoples Gas to increase spending to the lesser of the maximum under the price cap or the maximum scope of the programs that they can cost-effectively manage. ELPC Ex. 1.0 at 10.

The Utilities state that the Commission should reject Mr. Crandall's recommendations. The Plan is designed to meet the Utilities' statutory goals. Failure to

[5] The cost data included in the Plan are based on the savings levels that the Utilities calculated under their interpretation that excludes large volume transportation customer deliveries from the calculation of deliveries to retail customers.

meet the goals carries penalties under Section 8-104(i). 220 ILCS 5/8-104(i). Thus, the Utilities state that they have ample incentives to meet the statutory savings requirements. Mr. Crandall is correct that the Utilities have room under the rate impact budget cap, but, according to the Utilities, that is irrelevant. The cap is an exception to meeting those savings requirements; it is not a recommended spending level. Section 8-104 requires the Utilities to achieve specific savings. The Utilities state that their proposed Plan is designed to meet these requirements, and the Plan shows in detail how each will do so. The General Assembly could have elected to mandate spending up to the cap, but it did not make that policy decision. The Utilities argue that the Commission lacks the authority to substitute its policy decisions for the General Assembly and require the Utilities achieve savings in excess of the statutory levels or increase spending beyond what is needed to achieve the Utilities' requirements. The Utilities reiterate that one of their two overriding Plan objectives was to achieve the annual savings goals as cost effectively as possible. NS-PGL Ex. 1.0 at 4. Their Plan satisfies this objective.

The Utilities take no position on whether DCEO will be able to achieve their statutorily mandated savings level of 20%. If Mr. Crandall is suggesting that, if DCEO falls short of its requirements, this somehow means the Utilities have not achieved their savings requirements, the Utilities state that he is incorrect. Section 8-104(j) states that "[n]o utility shall be deemed to have failed to meet the energy efficiency standards to the extent any such failure is due to a failure of the Department." 220 ILCS 5/8-104(j). The Utilities' responsibility is clearly limited to 80% of the savings requirements, and they may use only 75% of available funding to meet their requirements. Section 8-104(e) states that "[t]he remaining 25% of available funding shall be used by the Department of Commerce and Economic Opportunity to implement energy efficiency measures that *achieve no less than 20% of the requirements of subsection (c) of this Section*." 220 ILCS 5/8-104(e) (emphasis added).

B. Staff's Position

1. Introduction to Savings Goals Issues

Sub-section 8-104(c) of the PUA states, in part:

> (c) Natural gas utilities shall implement cost-effective energy efficiency measures to meet at least the following natural gas savings requirements, *which shall be based upon the total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section*, during calendar year 2009 multiplied by the applicable percentage.

(220 ILCS 5/8-104(c), (emphasis added))

The above language clearly provides that the basis for computing natural gas savings requirements is the total amount of gas delivered to retail customers, with the exception of those customers described in subsection (m). The sub-section (m) referenced above deals with certain customers who, if their applications are approved by DCEO, are exempt from paying into and directly participating in the efficiency programs offered by the utility. Thus, aside from the sub-section (m) exclusion, the Act clearly provides that the basis for computing natural gas savings requirements begins with the total amount of gas delivered to retail customers.

Despite the clear language of Section 8-104(c) of the PUA, Peoples/NS chose to compute its natural gas savings goals based not on the "total amount of gas delivered to retail customers," but only on the gas delivered to retail customers who purchase their gas directly from Peoples/NS (hereafter "sales customers") and a portion of retail customers who purchase their gas from alternative gas suppliers (hereafter, "transportation customers").[6] In particular, Peoples/NS included transportation customers enrolled in the Company's "Choices for You" program, but excluded all other transportation customers. As discussed in sub-section (3) of this section below, Staff disagrees with the Company's exclusion of gas purchased by transportation customers. Staff recommends that the Commission direct the Company to include gas purchased by transportation customers in its calculations of gas savings goals, as indicated in the following table comparing Peoples/NS's calculations with Staff's revised calculations of Gas Savings Goals:

Gas Savings Goals (Therms per Plan Year)

	Plan Year	Company[7]	Staff[8]
N. Shore	PY 1	497,357	695,981
	PY 2	994,714	1,391,962
	PY 3	1,492,071	2,087,943
Peoples	PY 1	2,278,618	3,507,336
	PY 2	4,557,237	7,014,673
	PY 3	6,835,855	10,522,009

AG witness Philip H. Mosenthal appears to agree with Staff's position with respect to including gas purchased by transportation customers in the computation of the gas plan savings goals.[9] While Mr. Mosenthal does not provide an alternative computation of what he would believe to be the correct savings goals for Peoples/NS, he concludes that:

> The ICC should reject this plan and direct the Utilities to properly calculate its gas goals including all transportation gas delivered by the petitioner to end-use customers not falling under the subsection (m) exemption. The ICC should also direct the Utilities to properly calculate and document all subsection (m) exemptions, including providing explicit information about the number of customers, if any, that have applied for the SDC option, along with the gas load associated with those customers. Finally, the ICC should direct the Utilities to recalculate the rate impact caps to include gas

[6] NS-PGL Ex. 2.0 REV, pp. 14-15; and NS-PGL Ex. 2.5
[7] *Id.*
[8] Staff Ex. 2.2.
[9] AG Ex. 1.0, pp. 6-13.

> commodity costs for large volume transportation customers, based on a reasonable estimate.

(AG Ex. 1.0, p. 17) Staff takes no position with respect to Mr. Mosenthal's subsection (m) issue.

2. Introduction to Spending Limit Issues

The degree to which Peoples/NS may spend ratepayer funds on its natural gas energy efficiency programs is limited by statute. Subsection 8-104(d) of the PUA states, in part:

> (d) Notwithstanding the requirements of subsection (c) of this Section, a natural gas utility shall limit the amount of energy efficiency implemented in any 3-year reporting period established by subsection (f) of Section 8-104 of this Act, by an amount necessary to limit the estimated average increase in the ***amounts paid by retail customers in connection with natural gas service*** to no more than 2% in the applicable 3‑year reporting period.

(220 ILCS 5/8-104(d) (emphasis added))

The above portion of the statute appears unambiguous; i.e., over the course of each three year plan, expenditures should be limited to 2% of the "amounts paid by retail customers in connection with natural gas service." However, what may ***not*** be clear is the meaning of the phrase "amounts paid by retail customers in connection with natural gas service." Staff's view, apparently shared by Peoples/NS,[10] is that the computation of the natural gas plan spending limit should start with a definition of "amounts paid by retail customers in connection with natural gas service" that excludes amounts paid by large customers to non-certified alternative gas suppliers. On the other hand, Staff and the Company differ in how to interpret the last part of the phrase of the subsection, "to no more than 2% in the applicable 3‑year reporting period." In Staff's view, this means that the "amounts paid by retail customers in connection with natural gas service" must relate to the 3-year reporting period (in this case, June 2011 through May 2014), and Staff believes this can be accomplished by utilizing a forecast of revenues for that period. In contrast, Peoples/NS utilizes a forecast of only the first 12 months of that period (June 2011 through May 2012).[11] Unfortunately, Peoples/NS did not provide a forecast of the second and third years (June 2012 through May 2014). Nevertheless, Staff witness Zuraski stated, "Unless a better three year forecast becomes available, this tripling of the one year approach represents a reasonable approximation." (Staff Ex. 2.2)

Thus, the gas plan spending limits computed by Peoples/NS and Staff are the same, as shown in the following table:

[10] NS-PGL Ex. 2.0 REV, pp. 15-17.
[11] NS-PGL Ex. 2.0 REV, p. 16.

Gas Plan Spending Limits (Dollars over Three Years)

	Company[12]
N. Shore	$16,062,738
Peoples	$81,341,835

AG witness Mosenthal disagrees with both the Company and Staff with respect to the exclusion of amounts paid by large customers to non-certified alternative gas suppliers when computing the natural gas plan spending cap.[13] Further, he expressed the same concern that the Company incorrectly applied subsection (m) exemptions in relation to the spending cap calculation that he expressed in relation to the saving goals calculation. Finally, as with the saving goal calculation, Mr. Mosenthal does not compute what he would believe to be the correct spending cap for Peoples/NS; rather, he recommends that the Commission order the Company to re-calculate this number in light of his objections and concerns. Staff takes no position with respect to Mr. Mosenthal's subsection (m) issue. However, in the following subsection, Staff addresses the issue of whether and to what extent the Commission should permit the exclusion of large transportation customer data from the calculation of natural gas savings goals and spending limits.

3. Exclusion of Transportation Customers from Calculations of Savings Goals and Spending Limits

As noted in the previous two sections, Peoples/NS excluded volumes of gas purchased by its large transportation customers from the computation of savings goals, and Peoples/NS excluded dollars paid to alternative gas suppliers by the Company's large transportation customers from the computation of the natural gas plan spending limit. In Staff's view, the former was incorrect and the latter was correct. Staff takes up the matter of the spending limit first and the matter of the savings goal last.

a) Spending Limit

As noted in subsection (2) of this section, above, the statute is clear that expenditures should be limited to 2% of the "amounts paid by retail customers in connection with natural gas service." However, there was some question among legislators about how the "amounts paid by retail customers in connection with natural gas service" should be computed. In support of this assertion, Staff cites a portion of the legislative debate that took place regarding Senate Bill 1918, which was the bill that ultimately led to the inclusion of Section 8-104 in the PUA. In particular, pages 181-182 of the transcripts of the House debate, which took place on May 28, 2009, include the exchange reproduced on page 10, *supra.*

[12] Based on NS-PGL Ex. 2.0 REV, p 17, and NS-PGL Ex. 2.6 REV, which reflect revenues purportedly forecasted for the twelve months ending May 31, 2012 (rather than on a forecast for the 36 months ending May 31, 2014), times 3.

[13] AG Ex. 1.0, pp. 16-17.

As the documented exchange between Representatives Reitz and Flider above, attests, Representative Reitz sought clarification about what costs would be excluded and what costs would be included in connection with the computation of energy efficiency program charges, stating, “On the gas efficiency provisions, I'd like to make sure I understand how the charges to customers will be calculated.” In the course of the exchange, it becomes clear that the bill’s sponsor intended that the costs for this computation would ***exclude*** “wholesale commodity cost,” but would *include* “the utility's cost for transportation for that wholesale commodity,” along with “retail gas purchases from public utilities” and “retail gas purchases from *certified* alternative gas suppliers.”

It is a well-established principle of statutory construction that “[i]n aid of the process of construction we are at liberty, if the meaning be uncertain, to have recourse to the legislative history of the measure and the statements by those in charge of it during its consideration by the Congress.” (United States v. Great Northern Ry., 287 U.S. 144 (1932)) Explanatory legislative history is also consulted for narrowly focused explanation of the meaning of specific statutory language that a court believes is unclear.[14] In Illinois Courts, “a statute’s legislative history and debates are ‘[v]aluable construction aids in interpreting an ambiguous statute.’” Krohe v. City of Bloomington, 204 Ill. 2d 392, 398 (Ill. 2003) (quoting Advincula v. United Blood Services, 176 Ill. 2d 1, 19, 223 Ill. Dec. 1, 678 N.E.2d 1009 (1996)). Further, a statute is ambiguous “when it is capable of being understood by reasonably well-informed persons in two or more different senses.” (In re B.C., 176 Ill. 2d 536, 543, 680 N.E.2d 1355, 1359 (1997)) In this instance, there could be no better evidence of the statutory language being ambiguous and requiring explanation than the lawmakers themselves finding it necessary to have its meaning clarified through a colloquy on the House floor. Thus, Staff finds it appropriate to rely on the exchange between Representatives Reitz and Flider to better explain the legislative intent.

It is somewhat unfortunate that Representative Reitz, while trying to clarify which costs should be excluded, uses the term “wholesale.” The use of the term “wholesale” could lead one to think that he is not even talking about *retail* customers. However, it is clear from the surrounding sentences that this cannot be the case. It is clear from the context that the only reasonable interpretation is that “wholesale commodity cost” is being used as shorthand for the cost of gas purchased by a subset of the utility’s retail transportation customers, in particular those non-residential customers who are large enough that *non-certified* alternative gas suppliers may sell to them. Pursuant to Article XIX of the PUA[15] and Part 551 of the Commission’s rules,[16] to serve “residential customers”[17] and/or to serve “small commercial customers” (non-residential customers that use less than 5000 therms of natural gas per year[18]), an alternative gas supplier

[14] See, e.g., *Babbitt v. Sweet Home Chapter*, 515 U.S. 687, 704-06 (1995) (relying on committee explanations of word “take” in Endangered Species Act)
[15] 220 ILCS 5/19-100, *et seq*.
[16] 83 Ill. Adm. Code 551.10, *et seq*.
[17] Pursuant to 220 ILCS 5/19-105, a “residential customer” is “a customer who receives gas utility service for household purposes distributed to a dwelling of 2 or fewer units which is billed under a residential rate or gas utility service for household purposes distributed to a dwelling unit or units which is billed under a residential rate and is registered by a separate meter for each dwelling unit.”
[18] 220 ILCS 5/19-105.

must be certified by the Commission.[19] Serving non-residential customers that use *more* than 5000 therms per year does not require certification.[20] As already noted, the House debate clearly establishes that gas purchases from the utility and from *certified* alternative gas suppliers are to be included in the computation of charges, leaving out "wholesale" purchases, which, in context, and by a simple process of elimination, can only mean *non-certified* alternative gas suppliers.

4. Therm Savings Goal

While the House debate transcript cited and analyzed above is pertinent to the computation of the spending limit for gas energy efficiency program charges, it is *not* pertinent to the computation of gas savings goals or requirements. Nowhere in the entire exchange between Representatives Reitz and Flider is there any mention of therms, decatherms, MMBTU, cubic feet (or any other units of natural gas consumption). Nowhere in the entire exchange is there any mention of the savings goals or requirements. Rather, the exchange focuses on charges, the cost of the gas, the cost for delivery or transportation, and other expressions of money spent or to be spent rather than gas consumed or gas to be saved.

Staff recommendations with respect to the natural gas program spending constraint, on the one hand, and with respect to the natural gas program therm savings goals, on the other hand, may initially *appear* somewhat counterintuitive. However, upon closer examination, Staff's is the only interpretation of the statute that holds up to scrutiny, as explained below.

When a court interprets a statute, the primary objective is to ascertain and give effect to the intent of the legislature. (Illinois Bell Telephone Co. v. Illinois Commerce Comm'n, 262 Ill. App. 3d 266, 274 (1994)) The best indication of what the legislature intended is the statutory language itself. (Metro Utility Co. v. Illinois Commerce Comm'n, 262 Ill. App. 3d 266, 274 (1997)) Clear and unambiguous terms are to be given their plain and ordinary meaning (West Suburban Bank v. Attorneys' Title Insurance Fund, Inc., 326 Ill. App. 3d 502, 507 (2001)), and where statutory provisions are clear and unambiguous, the plain language as written must be given effect, without reading into it exceptions, limitations, or conditions that the legislature did not express. (Davis v. Toshiba Machine Co., 186 Ill. 2d 181, 184-85 (1999)) In this instance, the PUA is indeed clear and unambiguous regarding the computation of natural gas savings requirements, stating that they "shall be based upon the total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section, during calendar year 2009 multiplied by the applicable percentage." (220 ILCS 5/8-104(c)) Further, even if the statute was ambiguous, neither the portion of the legislative debate quoted above nor any other part of the recorded debate establishes that any transportation customer volumes should be excluded from the computation of savings goals.

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[19] *See* 220 ILCS 5/19-110(a)("The provisions of this Section [requiring Commission certification] shall apply only to alternative gas suppliers serving or seeking to serve residential or small commercial customers and only to the extent such alternative gas suppliers provide services to residential or small commercial customers.")

[20] *Id.*

Nevertheless, according to Peoples/NS witness Mr. Edward M. Korenchan:

> Because Section 8-104(c) specifies "gas delivered to retail customers" as the base, and the Transcripts [of the May 28, 2009 House debate, quoted from earlier] define large volume transportation as "wholesale," these volumes are excluded. The Utilities' small volume transportation customers ("Choices For You") are served by certified alternative gas suppliers and their deliveries are included as retail.

(NS-PGL Ex. 2.0 REV, p. 16) In essence, Company witness Mr. Korenchan believes that the two issues (therms savings and budget constraint) are linked by the singular notions of retail and wholesale that arise from the House debate. These singular notions require the retail entity to purchase small quantities (and the wholesale entity to purchase large quantities). This suggestion must be rejected for the following reasons.

First, if the General Assembly intended for the term "retail customers" to mean customers purchasing small quantities, throughout Section 8-104, then the addition of sub-section 8-104(m) would be meaningless. That sub-section indicates that the rest of 8-104 does not apply to:

> … customers of a natural gas utility that have a North American Industry Classification System code number that is 22111 or any such code number beginning with the digits 31, 32, or 33 and (i) annual usage in the aggregate of 4 million therms or more within the service territory of the affected gas utility or with aggregate usage of 8 million therms or more in this State and complying with the provisions of item (l) of this subsection (m); or (ii) using natural gas as feedstock and meeting the usage requirements described in item (i) of this subsection (m), to the extent such annual feedstock usage is greater than 60% of the customer's total annual usage of natural gas.

(220 ILCS 5/8-104(m))

All such customers who are described in the above excerpt are already "large" and hence outside of Mr. Korenchan's understanding of "retail customer's" common meaning. Why would the General Assembly bother to say (as it does in subsection (m)) that these *particular* large customers need to be excluded (not only from the saving goal calculations and the budget constraint calculations, but from the entirety of Section 8-104) if ***all*** large customers (in general) are already excluded? It is well established that "[a] fundamental rule of statutory construction requires that every part of a statute be presumed to have some effect, and not be treated as meaningless unless absolutely necessary." (<u>Raven Coal Corp. v. Absher</u>, 153 Va. 332, 149 S.E. 541 (1929)) Thus, the only conceivable answer, consistent with the tenets of statutory construction, is that the General Assembly would not have bothered to include subsection (m) if Mr. Korenchan's narrow understanding of "retail customer" was supposed to be applied generally to Section 8-104. From the standpoint of simple common sense, AG witness Mosenthal comes to a similar conclusion.[21]

[21] AG Ex. 1.0, pp. 14-15.

Second, use of the term "retail customers" to mean only customers purchasing small quantities is entirely inconsistent with other parts of the PUA (and other Illinois statutes dealing with retail customers) which clearly use the term to include both large and small customers. According to the maxim, *noscitur a sociis* ("a word is known by the company it keeps"), when a word is ambiguous, its meaning may be determined by reference to the rest of the statute.[22] Similarly, *in pari materia* ("upon the same matter or subject"), when a statute is ambiguous, its meaning may be determined in light of other statutes on the same subject matter.[23]

Accordingly, a directly relevant definition of "retail customer" is found in Section 16-102 of the PUA's Article XVI ("Electric Service Customer Choice and Rate Relief Law of 1997"), which states:

> "Retail customer" means a single entity using electric power or energy at a single premises and that (A) either (i) is receiving or is eligible to receive tariffed services from an electric utility, or (ii) that is served by a municipal system or electric cooperative within any area in which the municipal system or electric cooperative is or would be entitled to provide service under the law in effect immediately prior to the effective date of this amendatory Act of 1997, or (B) an entity which on the effective date of this Act was receiving electric service from a public utility and (i) was engaged in the practice of resale and redistribution of such electricity within a building prior to January 2, 1957, or (ii) was providing lighting services to tenants in a multi-occupancy building, but only to the extent such resale, redistribution or lighting service is authorized by the electric utility's tariffs that were on file with the Commission on the effective date of this Act.

(220 ILCS 5/16-102) As this definition clearly demonstrates, under the PUA "retail customer" is not synonymous with a customer purchasing small quantities.

Similarly, Section 7-210 of the PUA, which is entitled, "Commission oversight of nonpublic, unregulated sales at *retail* of natural gas by public utilities," states, *inter alia:*

[22] "The meaning of questionable words or phrases in a statute may be ascertained by reference to the meaning of words or phrases associated with it. (*Black's Law Dictionary* 956 (5th ed. 1979)) The maxim, while not an inescapable rule, is often wisely applied where a word is capable of many meanings in order to avoid the giving of unintended breadth to a legislative act. (*Jarecki v. G.D. Searle & Co.* (1961), 367 U.S. 303, 307, 6 L. Ed. 2d 859, 863, 81 S. Ct. 1579, 1582.)" Hayes v. Mercy Hosp. & Medical Ctr., 136 Ill. 2d 450, 477 (Ill. 1990).

[23] "Statutes which relate to the same thing or to the same subject or object are *in pari materia* although they were enacted at different times. It is a primary rule of statutory construction that not only should the intention of the legislature be deduced from a view of the whole statute and from its every material part, but statutes *in pari materia* should be construed together." 8 and 59. Also see People ex rel. Walsh v. Illinois Central Railroad Co. 409 Ill. 522; People ex rel. Goodman v. Wabash Railroad Co. 395 Ill. 520; People ex rel. Tolliver [*107] v. People ex rel. Harrell v. Baltimore and Ohio Railroad Co. 411 Ill. 55, 58-59, Wabash Railway Co. 378 Ill. 121; People ex rel. Reynolds v. Chicago, Burlington and Quincy Railroad Co. 295 Ill. 191; People ex rel. Graff v. Wabash Railway Co. 286 Ill. 15; and People ex rel. Nordstrom v. Chicago & N. W. R. Co., 11 Ill. 2d 99, 106 (Ill. 1957).

> (c) A gas utility offering unregulated sales of natural gas to an end‑use customer within or outside its service area shall be subject to Sections 7‑102(g), 7‑205, 7‑206, and 9‑230 with respect to such sales.
>
> (d) Notwithstanding any language of Article XIX to the contrary, a gas utility offering unregulated sales of natural gas to a residential customer or a small commercial customer within or outside its service area shall be subject to Sections 19‑110(e)(2), 19‑110(e)(3), 19‑110(e)(5), 19‑115, and 19‑120.

(220 ILCS 5/7‑210) In this Section 7-210, it is obvious that the *small* transportation customers described in sub-section (d) comprise merely a sub-set of all transportations customers described in sub-section (c), and that they are ***all*** considered to be *retail* customers.[24]

Both the PUA and other Illinois statutes contain other examples which clearly establish that, at least in the General Assembly's view, "retail customer" is not synonymous with a customer purchasing small quantities.[25]

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[24] If the title of the Section was not enough, Sub-section (l) states, "In addition to any other remedy provided in the Act, the Commission may order a gas utility to cease offering unregulated ***retail*** sales of natural gas in the State if it finds, after notice and hearing, that the gas utility willfully violated this Section." (220 ILCS 5/7‑210(l))

[25] For example, from the PUA's telecommunications article, see Sec. 13‑220.

> Sec. 13‑220. ***Retail*** telecommunications service. "Retail telecommunications service" means a telecommunications service sold to an end user. "Retail telecommunications service" does not include a telecommunications service provided by a telecommunications carrier to a telecommunications carrier, including to itself, as a component of, or for the provision of, telecommunications service. A business retail telecommunications service is a retail telecommunications service provided to a business end user. A residential retail telecommunications service is a retail telecommunications service provided to a residential end user.

(220 ILCS 5/13‑220).

The PUA's Section 20-102(b) states,

> (b) To date, as a result of the Electric Service Customer Choice and Rate Relief Law of 1997, thousands of ***large*** Illinois commercial and industrial consumers have experienced the benefits of a competitive ***retail*** electricity market. Alternative electric retail suppliers actively compete to supply electricity to large Illinois commercial and industrial consumers with attractive prices, terms, and conditions.

(220 ILCS 5/20-102(b).

As for other Illinois statutes, the Retailers' Occupation Tax Act includes this definition:

> "Sale at retail" means any transfer of the ownership of or title to tangible personal property to a purchaser, for the purpose of use or consumption, and not for the purpose of resale in any form as tangible personal property to the extent not first subjected to a use for which it was purchased, for a valuable consideration: Provided that the property purchased is deemed to be purchased for the purpose of resale, despite first being used, to the extent to which it is resold as an ingredient of an intentionally produced product or byproduct of manufacturing. For this purpose, slag produced as an incident to manufacturing pig iron or steel and sold is considered to be an intentionally produced byproduct of manufacturing. Transactions whereby the possession

For all the above reasons, for purposes of computing natural gas savings goals, Staff recommends that the Commission interpret the phrase "total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section" (220 ILCS 5/8-104(c)) to include deliveries to customers of all sizes, even if this seems at first blush contradictory vis-à-vis Staff's other recommendation to base the energy efficiency program budget constraint only on gas purchased from the utility and from ***certified*** alternative gas suppliers by residential and small commercial customers. In Staff's view, this necessarily dichotomous treatment is the only way to give meaning and effect to the legislative intent expressed in the May 28, 2009 House debate, without rendering Section 8-104 internally inconsistent.

C. AG's Position

1. Calculation of Natural Gas Savings Goals

As noted above, Section 8-104 of the Act sets out annual goals as a percent of gas consumption by year, as well as a spending cap of 2.0% of revenue each year.[26] Specifically, regarding savings goals, the Act states:

> Natural gas utilities shall implement cost-effective energy efficiency measures to meet at least the following natural gas savings requirements, which shall be based on the *total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section,* during calendar year 2009 multiplied by the applicable percentage.

220 ILCS 5/8-104(c) (emphasis added).

Section (m) goes on to exclude certain categories of customers. These include customers using gas for feedstock and some very large industrial customers falling into specific industrial classifications that have the option of applying for a self directed program:

> Subsections (a) through (k) of this Section do not apply to customers of a natural gas utility that have a North American Industry Classification System code number that is 22111 or any such code number beginning with the digits 31, 31, or 33 *and* (i) annual usage in the aggregate of 4 million therms or more within the service territory of the affected gas utility or with aggregate usage of 8 million therms or more in this State *and* complying with the provisions of item (1) of this subsection (m).

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of the property is transferred but the seller retains the title as security for payment of the selling price shall be deemed to be sales.

"Sale at retail" shall be construed to include any transfer of the ownership of or title to tangible personal property to a purchaser, for use or consumption by any other person to whom such purchaser may transfer the tangible personal property without a valuable consideration, and to include any transfer, whether made for or without a valuable consideration, for resale in any form as tangible personal property unless made in compliance with Section 2c of this Act [35 ILCS 120/2c].

(35 ILCS 120/1)

In none of the above examples does retail equate to small customers. Rather, the key factor tends to be whether the customer uses the good or service rather than re-selling it.

[26] *See* 220 ILCS 5/8-104 (c), (d) and (m).

220 ILCS 8-104(m) (emphasis added).

The statute refers to a "self-directing customer" (SDC) option that these large industrial customers can use in lieu of traditional program funding contributions and participation, which requires such customers to create an "energy efficiency reserve account" for the purpose of funding energy efficiency measures of the customer's choosing. 220 ILCS 5/8-104(m)(1)(B). Subsection (m)(1) requires that these customers have applied for the SDC option by February 2010. 220 ILCS 5/8-104(m)(1).

Both AG/CUB witness Phillip Mosenthal[27] and Staff witness Richard Zuraski testified that the Utilities' estimates of therms savings goals wrongly excludes vastly more transportation deliveries to its customers than permitted under Section 8-104(m). Specifically, the Utilities categorize all of their "transportation" deliveries to their customers as excluded except for those participating in the Customer Select Program (Rider 15) (roughly only a quarter of transportation deliveries). AG Ex. 1.0 at 6; Staff Ex. 2.0 at 3-6.

The Utilities assumed a very restrictive interpretation of the Act and are excluding vastly more transportation deliveries to their customers than permitted under the Act in calculating energy savings goals and rate impact caps. Specifically, the Utilities categorize all of their transportation deliveries to their customers as excluded except for those participating in the Utilities' "Choices For You" offering for small volume transportation customers.[28]

PGL/NS witness Edward Korenchan, in NS-PGL Ex. 2.5, shows the Utilities' 2009 gas deliveries used as the basis for its goals calculations. This exhibit shows total 2009 deliveries applicable to energy efficiency reduction of 1.1 billion therms for Peoples Gas and 248.6million therms for North Shore. The Utilities' gas deliveries, however, exclude therm sales to large volume transportation customers. Had the Utilities included therm sales to these customer groups in their Ex. 2.5 calculations, the total 2009 therms delivered that would be subject to energy efficiency reductions would increase from 1.1 billion therms to 3.5 billion for Peoples Gas, and from 248.6 million therms to 695.9 million therms for North Shore. AG Ex. 1.0 at 8. Including all

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[27] Mr. Mosenthal has developed numerous utility efficiency plans, and designed and evaluated utility and non-utility residential, commercial and industrial energy efficiency programs throughout North America, Europe and China. I have also completed or directed numerous studies of efficiency potential and economics in many locations, including China, Colorado, Kansas, Maine, Massachusetts, Michigan, New England, New Jersey, New York, Quebec, Texas, and Vermont. These studies ranged from high level assessments to extremely detailed, bottom-up assessments evaluating thousands of measures among numerous market segments. Recent examples of the latter are analyses of electric and natural gas efficiency and renewable potential along with the development of suggested programs for New York State, on behalf of the New York State Energy Research and Development Authority (NYSERDA). He is currently a lead advisor for business energy services in Rhode Island and Massachusetts on behalf of the Energy Efficiency Resource Management Council and the Energy Efficiency Advisory Council, respectively, overseeing and advising on utility program administrator's plans, program designs, implementation and performance. Mr. Mosenthal has been actively engaged in the Illinois Stakeholder Advisory Group (SAG) since its inception, representing the People. Prior to co-founding Optimal Energy in 1996, he was the Chief Consultant for the Mid-Atlantic Region for XENERGY, INC. (now KEMA). His resume is attached to his Direct testimony as AG Exhibit 1.1.

[28] PGL/NS Ex. 2.0 at. 16.

appropriate therm sales in the Utilities' target savings goals, as required by sections 8-104(c), (m) and (e) of the Act, substantially increases therm savings, as shown in the tables below. Note that this correction reflects an upper bound adjustment to the Utilities' calculations because it is likely a proportion of these excluded transportation customers' usage may qualify for exemption under Subsection (m). However, the calculation shows that a significant upward adjustment is necessary:

Peoples Gas					
Total Therm deliveries including ALL large volume transportation customers				3,507,336,492	
	Annual Incremental Goals Statutory	Cumulative Goals	Annual Incre Therm savings	Peoples Portion 80%	DCEO Portion 20%
PY 1	0.20%	0.20%	7,014,673	5,611,738	1,402,935
PY2	0.40%	0.60%	14,029,346	11,223,477	2,805,869
PY3	0.60%	1.20%	21,044,019	16,835,215	4,208,804
Total Therm Savings			42,088,038	33,670,430	8,417,608
Percent increase			308%		

AG Ex. 1.0 at 9.

For Peoples, cumulative savings would increase from 13.6 million therms to 42 million, inclusive of DCEO allocated savings, by the end of the plan period. This reflects more than a tripling of goals (308%):

North Shore Gas					
Total Therm deliveries including ALL large volume transportation custome				695,981,024	
	Annual Incremental Goals Statutory	Cumulative Goals	Annual Incre Therm savings	No Shore 80%	DCEO Portion 20%
PY 1	0.20%	0.20%	1,391,962	1,113,570	278,392
PY2	0.40%	0.60%	2,783,924	2,227,139	556,785
PY3	0.60%	1.20%	4,175,886	3,340,709	835,177
Total Therm Savings			8,351,772	6,681,418	1,670,354
Percent increase			280%		

AG Ex. 1.0 at 9.

For North Shore Gas, cumulative savings would increase from 2.9 million therms to 8.3 million, inclusive of DCEO allocated savings, by the end of the plan period -- just shy of a tripling of the Utilities' proposed goals. *Id.*

The Utilities exclusion of significant amounts of therm sales delivered to end use customers in their calculation of the statutory energy savings goals is based on PGL/NS witness Korenchan's interpretation of the legislative history of Section 8-104.[29] The history of the legislation, according to the Utilities, excludes large volume customers on the assumption that such customers are engaged in wholesale transactions with Peoples Gas and North Shore Gas. Mr. Korenchan asserts that because Section 8-104(c) specifies "gas delivered to retail customers" as the base, and the legislative transcripts define large volume transportation as "wholesale," these volumes are excluded. NS-PGL Ex. 2.0 at 15.

[29] NG-PGL Ex. 2.0 at 15 – 16.

The Commission should reject the Utilities reading of the Act. Section 8-104(c) is very clear in its exclusion of customers and the gas they use in the calculation of savings goals:

> Natural gas utilities shall implement cost-effective energy efficiency measures to meet at least the following natural gas savings requirements, *which shall be based upon the total amount of gas delivered to retail customers*, *other than the customers described in subsection (m) of this Section,* during calendar year 2009 multiplied by the applicable percentage.

220 ILCS 5/8-104(c) (emphasis added).

Section 8-104(m) provides a very specific application process for disqualifying customers from participation and assessment of charges associated with the energy efficiency programs provided under the Act:

> Subsections (a) through (k) of this Section do not apply to customers of a natural gas utility that have a North American Industry Classification System code number that is 22111 or any such code number beginning with the digits 31, 32, or 33 and (i) annual usage in the aggregate of 4 million therms or more within the service territory of the affected gas utility or with aggregate usage of 8 million therms or more in this State and complying with the provisions of item (l) of this subsection (m); or (ii) using natural gas as feedstock and meeting the usage requirements described in item (i) of this subsection (m), to the extent such annual feedstock usage is greater that 60% of the customer's total annual usage of natural gas.
>
> (1) Customers described in this subsection (m) of this Section shall apply, on a form approved on or before October 1, 2009 by the Department, to the Department to be designated as a self-directing customer ("SDC") or as an exempt customer using natural gas as a feedstock from which other products are made, including, but not limited to, feedstock for a hydrogen plant, on or before the 1st day of February, 2010. Thereafter, application may be made not less than 6 months before the filing date of the gas utility energy efficiency plan described in subsection (f) of this Section; however, a new customer that commences taking service from a natural gas utility after February 1, 2010 may apply to become a SDC or exempt customer up to 30 days after beginning service. …

220 ILCS 5/8-104(m)(1)(C). This section provides a specific application and certification process for self-directing customers (“SDCs”) with the Department of Commerce and Economic Opportunity (“DCEO”), and significantly, the requirement that these self-directing customers establish annual energy efficiency reserve accounts for purposes of participating in efficiency measures, albeit non-utility sponsored measures:

> (C) in the case of a SDC, the customer's certification that annual funding levels for the energy efficiency reserve account will be equal to 2% of the customer's cost of natural gas, composed of the customer's commodity cost and the delivery service charges paid to the gas utility, or $150,000, whichever is less;

220 ILCS 5/8-104(m).

This language makes clear that only these customers are to be excluded for purposes of calculating savings and spending goals. Nothing in the clear language of the statue provides or implies that large volume commodity shall be excluded from utility plan spending and savings goal amounts.

The issue as to which gas usage/therms should be excluded from the gas savings and spending calculation is further clarified in Section 8-104(e), the subpart clarifying cost recovery of the programs. Section 8-104(e) provides:

> A utility providing approved energy efficiency measures in this State shall be permitted to recover costs of those measures through an automatic adjustment clause tariff filed with and approved by the Commission. The tariff shall be established outside the context of a general rate case and *shall be applicable to the utility's customers other than the customers described in subsection (m) of this Section.*

220 ILCS 5/8-104(e). This provision makes clear that all of the utility's customers *except those who receive an exemption through subpart (m) of Section 8-104* shall be assessed the energy efficiency cost recovery charges. There is no exclusion in this language for retail, wholesale or non-Choices for You customers, as the Utilities argue. Clearly, the plain language of the Act provides that all of the Utilities' customers, except those described in subpart (m) of Section 8-104, shall participate in, help pay for the programs and have their therm usage included in the computation of energy savings.

The AG agrees with Staff about the Utilities' definition of "retail." The AG notes that if the legislature had intended for the term "retail customer" to exclude all these other gas deliveries they would have had no need to explicitly exempt those customers falling under subsection (m), since by definition they would already be excluded. Clearly, by carving out a very specific exemption for these customers, the legislative intent and plain language of the statute would otherwise include their gas consumption. Quite simply, there is no language in Section 8-104 to contradict the clear, limited exemption language of part (m) of Section 8-104, nor any suggestion that a "retail customer" of a local distribution gas company somehow includes only the commodity of residential and small business customers, but not larger commercial customers for purposes of calculating *both* gas savings goals and spending limits.

In addition, the plain language of the statute that savings goals shall be "based on the on the *total amount of gas delivered* to retail customers." [Emphasis added][30] The specific reference to "gas delivered" seems to clearly indicate an intent to focus on deliveries, not just commodity, and to ensure that *all gas delivered* is included. The Utilities do not normally classify these customers as "wholesale," and there is no justification for asserting these delivery customers are not retail customers of the Utilities. Certainly, if small customers purchasing commodity from a third party are considered "retail" — as the Utilities have asserted by including their transportation volumes — there is no reason just being larger would somehow make a customer become "wholesale" rather than "retail." Rather, the terms "retail" and "wholesale" should be considered based on standard English language definitions. The exclusion of "wholesale" customers would simply indicate that any gas deliveries to a customer for resale should be excluded (in other words, the customer could be viewed as a wholesale rather than retail customer if it is not the ultimate end-user of the gas). AG Ex. 1.0 at 10-11.

Also, the Act taken *in toto* clearly creates contradictions and illogical conclusions if one were to agree with the Company's interpretation. While Mr. Korenchan points to the legislative transcript, the colloquy itself sheds little light on the issue.

In the transcript referenced by the Utilities, Representative Reitz asks Representative Flider to clarify the distinction as to which customers are excluded by providing a specific example of "merchant electric generators" and asking if this "wholesale" customer would be included. Representative Flider responds "no." Merchant electric generators would be excluded under subsection (m) of the Act because they are effectively using gas as a wholesale feedstock to manufacture their electricity and resell that energy to ultimate customers. As a result, it is not persuasive to argue that Representative Flider's response can be viewed as necessarily applying to transportation customers that directly use gas for normal end uses.

Rep. Reitz then goes on to ask, "Stated differently, does the legislation intend to cover for the purposes of assessing charges, delivery service revenues and retail gas commodity purchases, but exclude wholesale gas purchases?" Rep. Flider answers "yes." However, this is simply a tautological question that elicits no new information. Put simply, Reitz has simply asked Flider to confirm whether the term "retail" means that retail is included and "wholesale" excluded. There is no indication of what Flider might consider a wholesale customer, and the context is still in reference to a merchant electric generator.

Rep. Reitz goes on to ask specifically about spending: "…so what is excluded is the wholesale commodity cost, the utilities' cost for transportation for that wholesale commodity is included, right?" Rep. Flider responds "That's correct, yes." Again, this passage sheds no light on what is meant by "wholesale gas purchases".

[30] *See* 220 ILCS 5/8-104 (c), (d) and (m).

What is clear is the plain language of Section 8-104. While transcripts of legislative debates can be helpful in elucidating vague statutory provisions that are subject to various interpretations, it is well-settled that when courts are interpreting a statute, the legislature's intent must be ascertained and given effect, and the determination as to intent begins with the plain and ordinary meaning of the statute without resorting to other aids. Metropolitan Life Ins. Co. v. Washburn*,* 112 Ill.2d 486,492 (1986). In addition, it is also a fundamental rule of statutory construction that where there exists a general statutory provision and a specific statutory provision, either in the same or in another act, both relating to the same subject the specific provision controls and should be applied. People v. Villarreal*,* 152 Ill.2d 3658, 379 (1992).

Section 8-104 clearly indicates that exemptions to gas savings and spending targets apply to any customer other than those who qualify under the very specific process outlined in Section 8-104(m). The Company's interpretation of this colloquy raises clear contradictions with the statute as a whole and the clear meaning of the words in parts (c), (e) and (m) of Section 8-104, as noted above. The Act is clear when it refers to the "total amount of gas *delivered*." To then count the delivery costs (implying the delivery service is clearly applicable as a "retail delivery customer"), but not the "total amount of gas" makes no sense. Also, there is an inconsistency in the Act if these customers' usage is excluded from efficiency spending, but section 8-104(e) requires collection of revenues for the programs from all customers except those identified in subpart (m).

In addition, the Act makes clear that even those customers of the gas utility who meet the requirements of the exemption provision must still set aside in an account an amount (2% of the customer's gas cost) dedicated to energy efficiency measures. Section 8-104(m) requires a SDC [self-directing customer] to set aside and certify annual funding levels for an energy efficiency reserve account will be equal to 2% of the customers cost of natural gas, composed of the customer's *commodity cost* and the delivery service charges paid to the gas utility." 220 ILCS 5/8-104(m)(1)(c). (Emphasis added). The Utilities' interpretation of Section 8-104 would create a new class of customers ("wholesale") with the distinction of being the only PGL/NS customers who would not have to participate in, and pay for, energy efficiency measures or programs. Nothing in Section 8-104 justifies such a conclusion.

Because the purpose of subsection (m) is clearly to allow these customers an exemption from the more traditional EEP funding mechanism, it again makes no sense that the legislature would choose to impose higher charges on them than other customers that can't meet the subsection (m) criteria. Under the Utilities' approach, self-directing customers would get penalized by reserving the full funds based on commodity plus delivery charges, but those who did not bother to apply as an SDC customer would have funding contribution calculations based on explicitly excluding commodity costs. This creates a clear inconsistency in the logic of the Act.

For all of the reasons stated above, the Commission should reject the Utilities' proposed Plan and order the Utilities to re-calculate the energy savings goals to include the large volume commodity sales in the calculation.

2. Calculation of Energy Efficiency Plan Spending Limits

As highlighted by AG witness Mosenthal, the Utilities are dramatically reducing their available rate impact spending levels as well as their energy efficiency statutory targets, based on their skewed interpretation of Section 8-104 of the Act. The result is the loss of millions of dollars in potential programs to benefit customers.

PGL/NS witness Korenchan testified that he calculated the spending calculations based on the same interpretation of Section 8-104 as used for calculating energy savings goals. As a result, the Utilities excluded retail revenues associated with gas commodity from large volume transportation customers for purposes of this calculation. PGL/NS witness Korenchan shows these calculations in Exhibit 2.6 and explains them in his testimony.[31]

Again, the Utilities clearly omit the commodity costs associated with the large volume transportation commodity. Effectively, the Utilities' approach creates some internal inconsistencies. The Utilities' have indicated these customers would be exposed to EEP rider charges,[32] paying into the funds at a consistent rate regardless of whether they purchased commodity from the Utilities. Presumably, the Utilities also intend for them to be eligible to participate in the EEP programs, since they would be paying into the fund. Therefore, allowing these customers to participate, and claiming savings from these customers, while not including their gas usage in the goals calculations clearly makes no sense. Instead, it provides a windfall source of very large potential savings that can be used to meet energy savings goals, while at the same time excluding their significant consumption from the goals calculations. In addition, including the commodity charges of the SDC customers in their reserve accounts — as Section 8-104(m) mandates, as described above — while not counting the commodity charges for those customers that do not qualify for SDC status, again results in an internally inconsistent policy.

In short, the Utilities have dramatically reduced both their energy efficiency statutory targets as well as their available rate impact cap spending levels. Mr. Mosenthal calculated that correcting this underestimate would result in goals that are *roughly three times higher than the Utilities have proposed*. AG Ex. 1.0 at 16. He testified that to calculate the spending side, one needs to estimate the average commodity cost these transportation customers are paying. For purposes of his calculation, he stated that while he would expect most of the larger transportation customers may be able to purchase their commodity at competitive rates that may be somewhat lower than the Utilities' commodity charges, he imagined under a competitive environment the Utilities would offer reasonably competitive supply. Therefore, he expected the underestimate of applicable revenue to calculate the rate cap to be of the

[31] NS-PGL Ex. 2.0 at 16-17.
[32] See NS-PGL Ex. 2.0 at 5-14, NS-PGL Ex. 2.1, and NS-PGL Ex. 2.2.

same general magnitude on a proportional basis — in other words also *roughly three times higher than the Utilities have proposed. Id.* Mr. Mosenthal further noted that while he believed the above estimated percentage increases are reasonably accurate, albeit the upper bound of the precise figure, he had no way to precisely calculate this for the Utilities with the information available to me at the time of filing testimony.

The ICC should reject the Utilities' Plan and direct the Utilities to properly calculate its gas goals including all transportation gas delivered by the petitioner to end-use customers not falling under the subsection (m) exemption. The ICC should also direct the Utilities to properly calculate and document all subsection (m) exemptions, including providing explicit information about the number of customers, if any, that have applied for the SDC option, along with the gas load associated with those customers. Finally, the ICC should direct the Utilities to recalculate the rate impact caps to include gas commodity costs for large volume transportation customers, based on a reasonable estimate.

The positive benefit to PGL/NS customers if the Utilities included all appropriate transportation customers in their determination of gas savings goals and budget is significant. Mr. Mosenthal noted that this recalculation would have the simple effect of significantly increasing savings and spending, thereby providing greater net benefits to the Utilities' customers. In addition, inclusion of these missing gas volumes would have a positive ripple effect across multiple utility service territories. AG Ex. 1.0 at 17-18.

For example, in addition to increasing savings and spending, additional secondary benefits to the overall portfolio include:

- EM&V spending limits, which the Utilities acknowledge are a resource constraint,[33] would also increase proportionally. This will enable better, and more extensive and timely evaluations.

- Reduced administrative costs as a percent of overall spending as programs are enlarged, and fixed costs for activities like planning, overhead, data tracking, and other areas are spread over greater levels of effort and savings.

- The Utilities could better match ComEd goals for joint and cooperative programs. This is important for a number of reasons. First, it avoids lost opportunities where a customer is engaged with a program but the Utilities cannot fully fund all the gas efficiency opportunities because of budget limits. Second, it potentially frees up some funds for ComEd to better meet its statutory goals under Section 8-103 of the Act, and focus on comprehensive solutions while limiting its spending by its more onerous rate cap.

Id. at 18.

[33] NS-PGL Ex. 1.0 at 23.

For all of these reasons, the Commission should reject the Utilities' proposed calculation of energy efficiency savings and spending and order them to re-calculate both, in accordance with Section 8-104, to exclude only the therms associated with Utilities' customers that satisfy subsection (m) of the law.

D. CUB-City's Position

1. Savings Goals

The PUA's incremental annual natural gas savings goals for Plan years 1, 2 and 3 are:

1) 0.2% of gas delivered by May 31, 2012;
2) an additional 0.4% of gas delivered by May 31, 2013, increasing total savings to 0.6%;
3) an additional 0.6% of gas delivered by May 31, 2014, increasing total savings to 1.2%.

The Utilities developed their portfolios independently, taking into account the uniqueness of their services areas. Both Peoples Gas and North Shore propose to offer the same eight programs, including both business and residential programs, with slight differences in program details and projected participation and savings levels as needed. The Utilities have separate savings and budget levels in their Plan as filed.[34]

The Utilities' Plan meets and exceeds the statutory natural gas savings targets using less funding than the utilities have at their disposition under the statutory spending limit. Peoples Gas estimates its statutory savings goals at 1,822,895, 3,645,790, and 5,468,684 therms for each Plan year respectively, and proposes savings targets that are slightly higher than the statutory goals -- 2,008,730, 3,765,524, and 5,469,566 therms per plan year, representing a savings of 0.22%, 0.41%, and 0.60% for each Plan year.[35] North Shore estimates its statutory savings goals at 397,886, 795,771, and 1,193,657 therms for each Plan year respectively, and like Peoples Gas, proposes Plan savings targets that are slightly higher than the statutory goals: 439,855, 841,844, and 1,232,243 therms each year, representing savings of 0.22%, 0.42%, and 0.62%.[36]

2. Spending Limits

Section 8-104(d) of the PUA limits the amount a utility can collect from its customers to pay for the energy efficiency measures it uses to meet the statutory energy savings goals:

> [A] natural gas utility shall limit the amount of energy efficiency implemented in any 3-year reporting period established by subsection (f) of Section 8-104 of this Act, by an amount necessary to limit the estimated

[34] NS-PGL Ex. 1.0 at 4-5.
[35] NS-PGL Ex. 1.2 at 7.
[36] NS-PGL Ex. 1.2 at 6.

> average increase in the amounts paid by retail customers in connection with natural gas service to no more than 2% in the applicable 3-year reporting period. The energy savings requirements in subsection (c) of this Section may be reduced by the Commission for the subject plan, if the utility demonstrates by substantial evidence that it is highly unlikely that the requirements could be achieved without exceeding the applicable spending limits in any 3-year reporting period.[37]

The amount of funding Peoples Gas has available under the statutory rate cap is $27,117,358, and North Shore $5,355,060.[38] The Utilities do not propose to spend all funds available under the PUA because they are able to meet the statutory savings targets without reaching the 2% rate cap. The Utilities propose to spend $26.7 million over their first three-year Plan, representing $22.5 million for Peoples Gas and $4.2 million for North Shore. (Those numbers do not include funding for DCEO).[39] Peoples Gas's programs will cost approximately $4 per therm, and North Shore's programs $1.66 per therm.[40] The rate impacts for the Utilities programs are projected at 0.81% for Peoples Gas and 0.80% for North Shore, amounts that are well below the statutory cap.[41]

CUB/City support the Utilities decision to spend less than the full amount available under the rate cap, because the Utilities appear able to cost-effectively meet the statutory gas savings targets set in Section 8-104 of the PUA.

Environmental Law and Policy Center ("ELPC") witness Geoff Crandall encourages the Commission to require the Utilities to expand their programs and spend the full amount allowed under the statutory rate cap.[42] However, the statute clearly defines the spending caps as maximums, not mandates to meet or exceed. Increasing the amount that Peoples Gas and North Shore plan to spend on their energy efficiency programs could result in greater energy savings, but it would also increase customers' bills. The intent of Section 8-104 of the PUA is clear from its mandate that if a utility demonstrates that it cannot meet the statutory savings requirements of within the spending limits, it should decrease the savings goals (as opposed to increasing the spending).[43] The legislature clearly prioritized the spending limits over the savings goals. The Utilities' Plan meets the savings targets, and requiring more spending to achieve savings beyond the targets is inconsistent with the Act.

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[37] 220 ILCS 5/8-104(d).

[38] *Id.*

[39] NS-PGL Ex. 1.0 at 12.

[40] *Id.*

[41] NS-PGL Ex. 2.0 at 10.

[42] ELPC Ex. 1.0 at 4-5.

[43] 220 ILCS 5/8-104(d).

E. ELPC's Position

1. NS/PGL ENERGY EFFICIENCY PLAN

The Illinois Legislature established an energy efficiency performance standard (EEPS) for Illinois' gas utilities in 2009, two years after it passed an electric EEPS. Like the electric statute, the gas EEPS requires utilities to save an increasing amount of energy each year within a budget cap. As described below, North Shore and Peoples Gas have developed plans that fall short of their statutory mandates in two ways: first, by improperly excluding transportation customers from the calculation of statutory savings goals and spending caps and, second, by choosing to design a portfolio that just barely meets the annual incremental savings goals instead of maximizing savings to comply with the company's longer term cumulative goals.

The Commission should require the Utilities to recalculate savings targets and spending caps by including <u>all</u> retail customers except those explicitly excluded by statute. Second, as it did in the Ameren case, the Commission should order the Utilities to use available but untapped funds not currently budgeted to achieve additional cost-effective savings.

2. The Utilities Improperly Excluded Large Volume Transportation Customers From the Calculation of Statutory Savings Goals and Spending Limits.

Peoples Gas calculates its overall 3-year savings goal as approximately 11 million therms with a budget cap of about $27 million. NS/PGL Ex. 1.2, 6 ("Plan"). North Shore calculates its 3-year savings goal as approximately 2.4 million therms and its spending limit as approximately $5.4 million. *Id.* When calculating these numbers, the Utilities excluded therm deliveries and commodity charges associated with Large Volume Transportation customers. NS/PGL Ex. 4.0, 3-4. The result is that the Utilities have "dramatically reduced both their energy efficiency statutory targets as well as their available rate impact cap spending levels." AG Ex. 1.0, 16.

In its Final Order in the Ameren case (Docket No. 10-0568), the Commission found that it was "incorrect" for Ameren to exclude the volumes of gas purchases from transportation customers from the computation of its savings goals. Ameren Final Order at 45. We agree and believe the Commission should make the same decision here. On the other hand, the Commission approved Ameren's exclusion of the same customers from its calculation of spending limits. *See id.* We disagree. The Commission acknowledged that its decision to include transportation customers in the calculation of savings targets but exclude them from the calculation of spending caps "may seem contradictory." *Id.* at 45. Nevertheless, it held that this distinction "comports with the statute" and its legislative history. *Id.* at 45. As we explain below, the statute makes no such distinction nor does the legislative history.[44]

[44] We believe the Commission's decision on this point was influenced, in part, by its misperception that the parties were "in agreement on Ameren's natural gas spending limit" (Order p. 44). ELPC is preparing an application for rehearing to correct the record on this point. In any event, the statute is clear that all retail customers except those explicitly excluded by subsection (m) should be included in the calculation

Subsection 8-104(c) of the PUA statute requires natural gas utilities to calculate savings targets based on deliveries to all “retail customers” except for a subset described in subsection (m) of the Act:

> Natural gas utilities shall implement cost-effective energy efficiency measures to meet at least the following natural gas savings requirements, which shall be based upon the total amount of gas delivered to *retail customers*, other than the *customers described in subsection (m)* of this Section, during calendar year 2009 multiplied by the applicable percentage. 220 ILCS 5/5-104(c).

Subsection (m) specifically states that the subset of customers excluded are only the customers that meet certain industrial categories and usage thresholds described further in the Act – specifically those customers that “have a North American Industry Classification System Code number that is 22111 or any such code number beginning with the digits 31, 32, or 33” and annual usage over 4 million therms or customers using natural gas as feedstock. 220 ILCS 5/8-104(m).

Then subsection (d) requires the spending cap to be based on the rate impact to all retail customers. In contrast to the savings goals described in subsection (c), there is no exclusion for subsection (m) or any other class of retail customers:

> Notwithstanding the requirements of subsection (c) of this Section, a natural gas utility shall limit the amount of energy efficiency implemented in any 3‑ year reporting period … by an amount necessary to limit the estimated average increase in the amounts paid by *retail customers* in connection with natural gas service to no more than 2% in the applicable 3 year reporting period. 220 ILCS 5/8-104(d).

Following subsection (d), subsection (e) clearly sets out the customers who have to pay for efficiency measures:

> A utility providing approved energy efficiency measures in this state shall be permitted to recover costs of those measures through an automatic adjustment clause tariff filed with and approved by the Commission. The tariff shall be established outside the context of a general rate case and shall be applicable to the utility’s customers other than the *customers described in subsection (m)* of this Section. 220 ILCS 5/8-104(e).

Thus, the key factors for performing all three of these calculations are (1) determining who is a “retail customer” and (2) determining which of these retail customers are “described in subsection (m).”

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of savings targets *and* spending limits and there is no basis to exclude transportation customers from either calculation.

The Utilities argue that "transportation customers" are not "retail customers." *See* NS-PGL Ex. 2.0, 15-16. Not so. The difference between retail customers and wholesale is a fairly basic principle: a retail customer is one who does not purchase natural gas for resale. Transportation customers do not "resell" the gas that is delivered to them. They are retail customers. As noted by AG witness Mosenthal:

> I see no reason just being larger would somehow make a customer become "wholesale" rather than "retail." Rather, the terms "retail" and "wholesale" should be considered based on standard English language definitions.

AG Ex. 1.0, 11. Transportation customers are "retail customers" and should have been included in the Utilities' calculation of savings goals. AG Ex. 1.0, 8.

Despite the plain language and common understanding of the terms "retail" and "wholesale", the Utilities attempt to support their exclusion of transportation customers with a transcript from a 2009 legislative debate in the House of Representatives. *See* NS-PGL Ex. 2.0, 15-16, reproduced on page 17, *supra.*

ELPC asserts that it is not clear, and the Utilities do not explain, how this legislative discussion supports the Utilities' interpretation of the statute. The transcript never even mentions transportation customers nor does it define the terms "wholesale" and "retail." In order to reach the conclusion it wants, NS-PGL would have to assume that Mr. Reitz confused "wholesale" with "retail," and that Representative Flider who is a former Illinois Power executive was confused as well. In reviewing the above, ELPC cannot see any evidence that the Representatives were using the term "wholesale commodity costs" as shorthand for the cost of gas purchased by a subset of the utility's retail transportation customers. As argued by AG Witness Mosenthal, a more reasonable interpretation is that the representatives were referring to merchant electric generators, not large volume transportation customers. *See* AG Ex. 1.0, 11-13.

In any event, it is only appropriate to turn to legislative history when the statutory language is not clear. Metropolitan Life Ins. Co. v. Washburn*,* 112 Ill.2d 486, 492 (1986). The best indication of what the legislature intended is the statutory language itself. Metro Utility Co. v. Illinois Commerce Comm'n, 262 Ill. App. 3d 266, 274 (1997). As explained in detail above, the language in 220 ILCS 5/8-104 clearly and unambiguously states that all retail customers except those excluded from subsection (m) should be included in the savings goal calculation. Thus, in this instance it would be improper to turn to the legislative history.

Furthermore, contrary to the Commission's decision in the Ameren case, there is no basis under the statute to *include* transportation customers when calculating the savings goals, and then *exclude* them when calculating spending caps. Subsection (c) (savings goals) and subsection (d) (spending caps) both use the phrase "retail customers." When the same words are used in the same statute they should be given the same meaning. Subsection (d) directs utilities to calculate their spending caps based on the amounts paid for natural gas service by all "retail customers." There is no exclusion – not even for "subsection (m)" customers. If the legislature had intended to exclude revenue from transportation customers from the calculation of spending limits it would have done so explicitly. When statutory provisions are clear and unambiguous, the plain language as written must be given effect, without reading into it exceptions, limitations, or conditions that the legislature did not express. *See Davis v. Toshiba Machine Co.*, 186 Ill. 2d 181, 184-85 (1999).

Finally, even assuming that the statute is ambiguous (which it is not), defining "retail customers" differently for the purposes of savings goals and spending caps would create "internal inconsistencies" as explained by AG witness Mosenthal:

> The Utilities' have indicated these [large volume transportation] customers would be exposed to EEP rider charges, paying into the funds at a consistent rate regardless of whether they purchased commodity from the Utilities. Presumably, the Utilities also intend for them to be eligible to participate in the EEP programs, since they would be paying into the fund. Therefore, allowing these customers to participate, and claiming savings from these customers, while not including their gas usage in the goals calculations clearly makes no logical sense. Rather, it would provide a windfall source of very large potential savings that can be used to meet energy savings goals, while at the same time excluding their significant consumption from the goals calculations. In addition, including the commodity charges of the [self-directed] SDC customers in their reserve accounts as Section 8-104(m) mandates, as described above, while not counting the commodity charges for those customers that do not qualify for SDC status, again results in an internally inconsistent policy.

AG Ex. 1.0, 15-16.

For all of these reasons, the Commission should require North Shore and Peoples Gas to recalculate their savings goals based on the total amount of gas delivered to *all retail customers* except for those customers that the company properly identifies under subsection (m). Staff Exhibit 2.2 presents this calculation in graphic form.

	North Shore		**Peoples**	
	Company's Computation	Staff's Computation	Company's Computation	Staff's Computation
PY1	497,357	695,981	2,278,618	3,507,336
PY2	994,714	1,391,962	4,557,237	7,014,673
PY3	1,492,071	2,087,943	6,835,855	10,522,009

Staff Ex. 2.0, 5-6 and Ex. 2.2. Similarly, the Commission should require the Utilities to recalculate their spending limits based on the average increases in amounts paid by all retail customers with no exclusion, as set forth in subsection (d).

3. The Utilities' Planned Levels of Spending and Savings Are Inadequate.

The plans proposed by North Shore and Peoples will allow the Utilities to "just barely" meet their annual incremental statutory savings goals, assuming that all goes according to plan. ELPC Ex. 1.0, 4. As noted by ELPC witness Crandall, Peoples and North Shore would satisfy their mandatory statutory therm targets with an excess of 2.2% and 4.2%, respectively, for the plan cycle. *Id.* At the same time, even under the utilities' proposed method for calculating the cap, both Utilities could "more than double" their spending over the three-year plan period and still stay within their spending caps. *Id.* (citing ELPC Ex. 1.4).

Peoples Gas Three Year Budget (PY1 – PY3)

	PY1	PY2	PY3
Proposed Budget	$7.6 million	$10.9 million	$14.3 million
Available	$27.1	$27.1	$27.1
% of Available Funding	28.1%	40.5%	53.1%

Needless to say, they could produce significantly greater savings under spending limits that properly include commodity charges associated with transportation customers.

Mr. Crandall is concerned that this level of spending and savings is "inadequate given the available program funds, the significant benefits of energy efficiency to Illinois ratepayers, and the risk that the Utilities will fall short of statutory goals." ELPC Ex. 1.0, 3. As described below, the Utilities' decision to leave millions of dollars on the table is flawed for at least three separate reasons:

4. The Utilities' failure to use all available resources will undermine their ability to comply with future cumulative savings requirements.

In contrast to the electric statute, the natural gas EEPS explicitly includes cumulative goals. In other words, *any* savings achieved after May 31, 2011 count towards the savings targets in the Act:

> (c) Natural gas utilities shall implement cost-effective energy efficiency measures to meet *at least* the following natural gas savings requirements, which shall be based upon the total amount of gas delivered to retail customers, other than the customers described in subsection (m) of this Section, during calendar year 2009 multiplied by the applicable percentage. Natural gas utilities may comply with this

> Section by meeting the *annual incremental savings goal in the applicable year or by showing that total savings associated with measures implemented after May 31, 2011 were equal to the sum of each annual incremental savings requirement from May 31, 2011 through the end of the applicable year*.

220 ILCS 5/8-104(c) (emphasis added).

These savings goals start low (0.2% of retail gas deliveries in the first year) but ramp up quickly over time: three times the cumulative therm savings are required by 2013 (0.6%); six times the savings by 2014 (1.2%); ten times by 2015 (2.0%); fifteen by 2016 (3.0%) and so on. By 2020, the statute will have required the Utilities to accumulate *forty-three times* the therm savings they need to save in 2012.[45]

In contrast, the statutory spending cap does not grow over time and remains at a flat 2% throughout future planning periods. *See* 220 ILCS 5/8-104(d); *see also* Ameren Order at 30 ("The Commission recognizes that the statute imposes an ever greater energy efficiency savings requirement on Ameren each year, without a proportionate increase in funding."). Because the spending cap is annual, the Utilities must "use it or lose it." By leaving millions of dollars unspent in this Plan (when goals are comparatively easy to meet), the Utilities are setting themselves up to fail in the future.

In the Ameren case, the Commission recognized that unless a change is made to the spending caps in the statute, it will become "increasingly difficult" for utilities to meet the statutory savings targets. (Ameren Order at 29). Thus, when developing energy efficiency plans, Utilities should be "mindful of the savings requirements that will be expected in the next Plan" (*Id.* at 45) and should "develop innovative processes to leverage the available funding to implement the will of the Legislature." (*Id.* at 31) The North Shore and Peoples Gas Plan acknowledges that all of the Utilities' programs are "scalable" and "can easily expand to incorporate additional cost-effective measures in the future." NS-PGL Ex. 1.2 (Plan) at 41. The Commission should reject the Utilities' bare minimum approach in this case and direct the Utilities to submit a compliance filing that maximizes their ability to meet future savings goals.

5. The Utilities' failure to invest in cost-effective energy efficiency will hurt ratepayers and violates their obligation to provide least cost service.

Cost-effective energy efficiency programs are good for ratepayers and good for the Illinois economy. As noted by ELPC witness Crandall, "Peoples' and North Shore's ratepayers – residents and businesses – on average benefit from the maximum implementation of cost-effective energy efficiency programs." ELPC Ex. 1.0, 11. Mr. Crandall observes:

[45] *Compare* 220 ILCS 5/8-104(c)(9) (requiring 8.6% cumulative savings in 2020) *with* 220 ILCS 5/8-104(c)(1) (requiring 0.2% cumulative savings by 2012).

> For each dollar invested in energy efficiency, Peoples and North Shore ratepayers will benefit, and as a result, there will be economic and environmental benefits flowing to Illinois residents and businesses. Less energy will be consumed, and as long as the total resource cost (TRC) test benefit-cost ratios exceed 1.0, Illinois residents and businesses will on average expend less money on their energy service needs than they would have without the energy efficiency programs.

ELPC Ex. 1.0, 5.

The portfolio-wide TRC benefit cost ratio is 2.05 for North Shore Gas and 2.24 for Peoples Gas. NS-PGL Ex. 1.2, 9. This means that each dollar of lost investment represents more than two dollars of lost opportunity for Illinois ratepayers and the utility system. The Utilities argue that they chose to underspend in order to "minimize impacts on ratepayers." NS-PGL Ex. 3.0, 19. However, the record contains no evidence that the Utilities evaluated bill *savings* that result from energy efficiency. At the hearing, Company witness Korenchan acknowledged that the Utilities' "bill impact" evaluation consists of nothing more than a mathematical application of the Rider EOA charges to customer bills and does not account for participant bill savings that might result from reduced therm usage or changes in natural gas prices. Tr. 66 (cross examination of Mr. Korenchan). If the Utilities *had* examined bill savings, they would have likely discovered that additional spending on cost-effective EE programs would help customers save money as described by witness Crandall above.

Public utilities have an obligation to provide "reliable energy services at the least possible cost to the citizens of the State." 220 ILCS 5/1-102. The Utilities' failure to maximize savings violates their obligation to provide service that is in "all respects adequate, efficient, just, and reasonable." 220 ILCS 8-101. Furthermore, Subsection (a) of the gas EEPS states that "natural gas utilities and the Department of Commerce and Economic Opportunity *are required* to use cost-effective energy efficiency to *reduce direct and indirect costs to consumers*. 220 ILCS 5/8-104(a). Subsection (c) clearly indicates that the savings goals are floors, not ceilings. "Natural gas utilities shall implement cost-effective energy efficiency measures to meet *at least* the following natural gas savings requirements …." 220 ILCS 5/8-104(c). In light of these statutory requirements, the Commission should reject the Utilities' Plan and require them to refile a Plan that delivers additional cost-effective savings to their customers. (Emphasis Supplied)

6. The Utilities' constrained budget will result in lost opportunities for joint gas-electric savings and other secondary benefits.

AG witness Mosenthal explains that increasing savings and spending would provide greater net benefits to the Utilities' customers but would also have a "positive ripple effect across multiple utility service territories." AG Ex. 1.0, 17. For example, enhanced EM&V resources would "enable better, and more extensive and timely evaluations" and fixed costs for activities like planning, overhead, and data tracking could be "spread over greater levels of effort and savings." *Id.* Perhaps most significantly, an enhanced North Shore and Peoples Gas Plan could allow the Utilities to "better match ComEd goals for joint and cooperative programs." *Id.*

Joint delivery and coordination of electric and gas energy efficiency programs "can help leverage savings across multiple utility services, reduce administrative costs, and provide a higher level of customer service by addressing all their energy needs in a one-stop-shopping fashion." AG Ex. 1.0 at 50. It is particularly important for the Commission to encourage joint delivery in order to stretch constrained resources under the electric and gas EEPS to maximum effect. Although North Shore and Peoples are planning to jointly deliver certain programs, their efforts are hampered by the relatively small size of the gas programs as compared to ComEd's larger electric budgets. As witness Marks acknowledges:

> The ability of the Utilities to match the level of effort in jointly delivered programs with ComEd is constrained by the fact that our goals for the first 3-year plan period are 0.2%, 0.4% and 0.6%. ComEd's goals for the same period are 0.8%, 1.0% and 1.2% respectively.

NS-PGL Ex. 3.0, 22. What Marks fails to acknowledge, however, is that these goals are *minimums* not maximums and the Utilities have left millions of dollars of available funding unspent that could have been directed towards joint and cooperative programs. Thus, Mr. Marks is not correct that the Utilities "cannot" match ComEd's level of effort. *See Id.* at 22. Rather, the Utilities are *choosing* not to do so.

With more funding, the Utilities could "better match ComEd goals for joint and cooperative programs." AG Ex. 1.0, 18. Mr. Mosenthal explains that this is important for a number of reasons:

> First, it avoids lost opportunities where a customer is engaged with a program but the Utilities cannot fully fund all the gas efficiency opportunities because of budget limits. Second, it potentially frees up some funds for ComEd to better meet its statutory goals under Section 8-103 of the Act, and focus on comprehensive solutions while limiting its spending by its more onerous rate cap.

Id.

In the Ameren case, the Commission found that "the potential benefit to all customers on the energy efficiency front, both gas and electric, warrant Ameren to develop a plan to spend excess gas energy efficiency funds on joint gas-electric savings." Ameren Order at 29. The Commission therefore ordered Ameren to "work with the SAG" to identify opportunities to "expend excess funds available in any year that are over and above what Ameren expects to spend on gas savings, to the extent possible, toward joint gas-electric savings opportunities that Ameren can identify." *Id.* at 45.

Although Ameren is a joint electric and gas utility, the Commission's reasoning in that case applies with equal force here. North Shore and Peoples have not designed plans that are "mindful of the savings requirements that will be expected in the next Plan" nor have they maximized opportunities for customer savings. *C.f.* Ameren Order at 45. For all of the reasons discussed above, the Commission should reject the NS-PGL Plan and require the Utilities to first recalculate their planned savings targets and spending limits consistent with the discussion in Section II.A above, and then refile a Plan that maximizes savings to comply with the Utilities' long term cumulative goals and obligations to provide least cost service.

F. Commission Analysis and Conclusions

It is well-settled that when courts are interpreting a statute, the legislature's intent must be ascertained and given effect, and the determination as to intent begins with the plain and ordinary meaning of the statute without resorting to other aids. In addition, it is also a fundamental rule of statutory construction that where there exists a general statutory provision and a specific statutory provision, either in the same or in another act, both relating to the same subject the specific provision controls and should be applied.

Section 8-104 clearly indicates that exemptions to gas savings and spending targets apply to any customer other than those who qualify under the very specific process outlined in Section 8-104(m). The Company's interpretation of the legislative colloquy raises clear contradictions with the statute as a whole and the clear meaning of the words in parts (c), (e) and (m) of Section 8-104, as noted above. The Act is clear when it refers to the "total amount of gas delivered." Furthermore, it is illogical to count the delivery costs, but not the total amount of gas. We agree with Staff that the Utilities interpretation of the meaning of retail customer in the statute is inconsistent with its meaning in other parts of the PUA.

The key factor in determining the applicability of Section 8-104 is whether the customer uses the commodity or resells it. The Utilities are directed to recalculate spending limitations in accordance with the interpretation of Section 8-104 advanced by Commission Staff and Intervenors.

Similarly, in calculating the savings requirements, the Commission finds that Staff's calculation of the rate impact cap is consistent with Section 8-104 of the Act. The Utilities are directed to exclude only the therms associated with customers that satisfy the exclusions of Section 104(m).

V. EVALUATION, MEASUREMENT & VERIFICATION

A. North Shore/Peoples Gas' Position

1. EMV Framework

Mr. Marks states that the Utilities' Plan assumes that the Commission approves deemed savings for the full three-year Plan Period. Deemed savings are estimates for the savings that each measure will be credited for. They are "deemed" to be reasonable. Thus, Mr. Marks states that the measure savings are fixed for the approved period and used to determine if the Utilities meet their requirements. To gauge portfolio performance, clear and consistent evaluation standards must exist prior to program implementation. NS-PGL Ex. 1.0 at 15-16.

Mr. Marks states that the technical assumptions used to develop the deemed savings values are based on many sources, including engineering knowledge, industry expert input, manufacturer's information and historical program experience using other utility deemed savings values. The Plan's technical assumptions describe the baseline energy values for each measure in each program. The technical assumptions detail the high efficiency options for each measure, compared to the baseline option. The difference between the high efficiency and baseline options is the measure's savings. Mr. Marks states that these technical assumptions include: operating hours; net-to-gross ("NTG") ratio; measure lifetime; customer savings per measure; and incremental measure cost. NS-PGL Ex. 1.0 at 15-16.

The deemed savings include NTG adjustments. Possible adjustments include: free riders; participant spillover; non-participant spillover; and measure persistence. "Free riders" are participants who would have taken the same action without the program. "Participant spillover" means participants who take additional actions as a result of the program but do not receive any incentives. "Non-participant spillover" can take a number of forms, *e.g.* a customer takes an action as a result of the program, (1) but does not qualify for any incentive; (2) and does qualify for an incentive, but he does not apply for it. In both cases, the energy savings never get credited to the program. "Measure persistence" means efficiency measures that are credited as program participants but are removed or not replaced when they fail prematurely. NS-PGL Ex. 1.0 at 21.

The Utilities proposed that the deemed values would be <u>prospectively</u> subject to evaluation, measurement and verification ("EM&V"). They would apply the evaluation results in the next three-year planning period. The results would not adjust the deemed values approved in this proceeding. NS-PGL Ex. 1.0 at 21.

Mr. Marks explains that many of the arguments regarding fixed values, deeming, NTG and related issues could be grouped into something called a realization rate. NS-PGL Ex. 3.0 at 2. He defined a "realization rate" in this context as the total difference between what the utility initially claims as savings for any energy efficiency measure and what is counted as final savings towards meeting the targets. Anything that is subject to change by either the implementation contractor or independent evaluator will affect the realization rate. NS-PGL Ex. 3.0 at 3.

To address broadly the concerns and criticisms of Messrs. Mosenthal and Crandall, Mr. Marks, in his rebuttal testimony, elaborated on the EM&V framework presented in his direct testimony.

In general, the Utilities' proposed framework captures all the key components to updating realization rates. Mr. Marks states that this framework negates the need for explicit Commission guidance for realization rates. If the Commission directs the independent evaluator to calculate Plan energy savings as the product of verified participation, unit savings, and NTG ratios and if the Commission provides guidance with regard to the use of fixed/deemed values and prospective/retrospective application, then all issues related to realization rates can be addressed through the definition of fixed/deemed values or through the independent evaluator's assessment of retrospective evaluation results. NS-PGL Ex. 3.0 at 3.

Mr. Marks states that the Utilities' EM&V framework is comprised of the following five components:

- Evaluation cycle: Independent evaluator conducts at least one impact evaluation and one process evaluation for each program during the Plan Period.

- Gross savings for standard measures: Gross savings is savings prior to any NTG adjustment. The two factors needed to calculate gross savings are participation and measure unit savings. The independent evaluator would verify and update participation values each year. Similarly, unit savings values would be updated annually based upon available evaluation results, for application in the beginning of each new Plan year. Changes in unit savings values would always be applied <u>prospectively</u>. As new evaluation results are completed, unit savings values would be applied prospectively in the following Plan year. For example, evaluation results completed prior to March 1 would be incorporated the following Plan year, which begins June 1.

- Impacts for custom measures: The independent evaluator would annually verify impacts for custom measures. The Utilities would apply any changes *retrospectively.*

- NTG ratios: NTG ratio values would remain unchanged for the entire three-year Plan Period.

- Development of a technical reference manual: Each utility would develop a technical reference manual ("TRM") to document the algorithms and assumptions used to derive each input.

NS-PGL Ex. 3.0 at 4-6. Retroactively applying evaluation results would negatively affect Plan implementation and delivery of programs and savings to customers. For example, assume that an EM&V study results in a 50% reduction in program savings for a given measure. The Utilities would be forced to spend more money trying to make up for the lost savings. Another outcome may be that they discontinue that measure immediately given the high cost per therm saved and the likelihood that it would fail the total resource cost ("TRC") test at these reduced savings levels. Mr. Marks states that this has a profound impact on implementation activity. Program implementation strategies require significant planning and support from trade allies, education of customers, marketing and promotion campaigns, building of infrastructure, *etc*. This takes many months of effort and significant investment. Making substantial changes midstream because of a "bad" EM&V result can be disruptive and costly. Mr. Marks states that it is more effective to apply EM&V to future planning and use the information to modify and optimize program designs. These types of changes should be transitional and planned out carefully. NS-PGL Ex. 1.0 at 23-24.

The Utilities state that their proposed EM&V framework comprehensively and clearly addresses comments and concerns about calculating savings. They state that their framework is a reasonable way to balance concern about accurately and timely calculating savings with the risk to the Utilities of changing the rules in the middle of the Plan Period when making mid-course corrections to meet statutory requirements may not be feasible.

2. Evaluation Contractor Contract

Dr. Brightwell recommends that the Commission require the Utilities to include in the contracts they enter into with evaluators language that would (1) allow the Commission to terminate a contract if it determines that the evaluator was not acting independently; and (2) prevent the Utilities from terminating the contract without Commission approval. ICC Staff Ex. 1.0 at 6. Mr. Marks states that the Utilities do not necessarily oppose the proposals, but they have two concerns. On the first point, they are concerned about process. The law imposes evaluation requirements and a budget cap. According to Mr. Marks, it is not evident from Dr. Brightwell's testimony or the cited rehearing orders how the Commission would go about terminating a contract. If the Utilities receive notice and an opportunity to respond and if they have a chance to address the potential adverse effects on submitting timely reports and staying within budget, Mr. Marks states that this could alleviate some concerns. On the second point, Mr. Marks states that the Utilities' contracts often have standard requirements, the breach of which is cause for termination (e.g., insurance coverage or conduct when on the Utilities' premises). If the requirement for Commission approval could preclude the Utilities from terminating a contract for such breaches, Mr. Marks states that would be troubling. If these concerns can be addressed by contract language that recognizes the purpose is solely the independence of the evaluator and that adverse consequences on timing and budget would be addressed, the Utilities would not oppose the proposals. NS-PGL Ex. 3.0 at 23-24.

3. Evaluation Cycle

Mr. Marks states that only Mr. Mosenthal opposed a three-year evaluation cycle approach. Mr. Mosenthal states that the Utilities' approach for one evaluation per program per Plan cycle is too "prescriptive" and instead recommends a deliberative process through which "the SAG [stakeholder advisory group], in concert with the evaluation contractors, explore these trade-offs and work together to develop EM&V high-level plans." AG Ex. 1.0 at 43-45. The Utilities disagree that their proposed EM&V framework is prescriptive or rigid. Mr. Marks states that the Utilities will be flexible based upon the availability of funds and where those funds can best be used. They will rely on the expertise of our independent EM&V contractors for many of these decisions. NS-PGL Ex. 3.0 at 6.

The Utilities state that resolution of any EM&V issues must recognize the statutory limitation on spending for evaluation. Specifically, Section 8-104(f)(8) states that "[t]he resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given 3-year period." 220 ILCS 5/8-104(f)(8). Mr. Marks states that this necessarily means that the EM&V budgets are small in the first two years of the Plan Period and cannot support EM&V for all programs. Navigant Consulting, Inc. ("Navigant") the Utilities' independent EM&V contractor, expressed some concern about its ability to conduct EM&V with a budget equal to just 3% of the portfolio costs. Thus, the Utilities expect to have EM&V results for only some programs. NS-PGL Ex. 1.0 at 23.

Dr. Brightwell requests the Commission provide guidance on budget limit on evaluation costs. ICC Staff Ex. 1.0 at 6-7. In response, the Utilities note that they assumed that 3% of the total budget would be the cap for spending on evaluation. The Utilities made this calculation for each year of the three-year plan, and the Utilities intend to impose this cap on a year-by-year basis. Thus, spending will increase proportionately with the budget. NS-PGL Ex. 3.0 at 24.

4. Fixed Values

a) Standard Measures

Mr. Marks states that most witnesses expressed no opinions on deeming of fixed inputs used to calculate gross savings. Mr. Mosenthal states "I support the concept of deeming gross measure savings so long as they are restricted to standard or 'prescriptive' measures, … ." (AG Ex. 1.0 at 25). This seems to be consistent with the Utilities' approach.

Mr. Marks states that the Utilities' Plan includes proposed values for all inputs to be used in calculating annual energy savings. He also states that it is imperative that the Commission approve a set of fixed input values in this proceeding. Any changes could ripple through to the portfolio savings calculations and, possibly, spending calculations. Mr. Marks states that, if the Commission approves other fixed input values after finalizing portfolio savings goals and spending levels, this might force the case to be reopened to ensure that savings or spending targets are consistent with approved fixed input values. NS-PGL Ex. 3.0 at 7.

Mr. Marks states that most parties offered no position on the specific fixed input values. However, Mr. Mosenthal cited limited time and resources and goes on to "suggest the ICC only *provisionally deem measure savings values*, and direct that the Utilities address any appropriate modifications with the SAG." AG Ex. 1.0 at 25 (emphasis in original). Both Mr. Mosenthal and Mr. Crandall expressed some concerns about some of the specific fixed value assumptions. Mr. Crandall's solution was to develop a TRM (ELPC Ex. 1.0 at 20), which the Utilities do not oppose. Mr. Mosenthal provided no alternatives, firm timeline or process for approving final values outside of an "ongoing SAG process." AG Ex. 1.0 at 26.

Mr. Marks responds that the parties had eight weeks to review and gather discovery regarding the Utilities' proposed fixed input values, and they chose to offer no alternatives for the Commission to consider. The Utilities provided a sound basis for the proposed fixed values. The Commission should accept the fixed input values that the Utilities proposed. NS-PGL Ex. 3.0 at 8.

b) Custom Measures

Mr. Marks states that there were no intervener positions contrary to the proposed EM&V framework for custom measures. Mr. Mosenthal states "[n]o deeming of gross measure savings should be permitted for any 'custom' measures." AG Ex. 1.0 at 26. This is consistent with the Utilities' approach. According to Mr. Marks, Mr. Mosenthal later incorrectly states that "I can only conclude [Peoples Gas] and [North Shore] are proposing that this value be deemed for any custom project, regardless of the actual measures, customer size, or other unique variables." AG Ex. 1.0 at 28. In fact, Mr. Marks states that the Utilities did not assume any custom measure to be deemed. He said this is evident from the Plan. *See, e.g.,* NS-PGL Ex. 1.2 at 77, which describes the Commercial and Industrial Customer Custom Rebates Program in detail and includes the explanation: "Per unit savings of 5,400 therms is used as a proxy and not considered to be a deemed savings. Individual project savings will be determined on a case by case basis and reflect the actual project scope." The data to which Mr. Mosenthal is referring were used for benefit cost testing purposes only. The Utilities state that they will estimate custom measures on a project-by-project basis using the specific characteristics for each customer. They will use these estimates to calculate incentives. Finally, as shown in the proposed EM&V framework, the Utilities state that they will only take credit for the savings that are validated by the independent evaluator. NS-PGL Ex. 3.0 at 9.

c) Net-to-Gross

Mr. Marks states that Mr. Crandall did not agree with holding NTG ratios constant for the full three-year plan period although his recommendation was not that different. He recommends prospective adjustments, as the Utilities do, but he wants EM&V results to be applied once they become available. ELPC Ex. 1.0 at 22. While Mr. Marks believes that Mr. Crandall appears to support the policy framework that Mr. Mosenthal proposed in a memorandum he provided to the stakeholders (AG Ex. 1.2), he is not suggesting any retrospective application. ELPC Ex. 1.0 at 22; NS-PGL Ex. 3.0 at 9-10.

Mr. Marks states that Mr. Mosenthal has significantly different proposals. The Utilities propose that savings be calculated using NTG ratios that remain fixed for the entire three-year Plan cycle. NS-PGL Ex. 3.0 at 10. Mr. Mosenthal proposes that NTG ratios be updated within the Plan cycle and that NTG ratios be applied retrospectively in some circumstances, namely:

- For "existing and new programs not yet evaluated";
- For "previously evaluated programs undergoing significant changes — either in the program design or delivery, or changes in the market itself."

AG Ex. 1.0 at 40.

Mr. Marks states that the framework that Mr. Mosenthal is advocating provides no clarity for which programs would be subject to retrospective treatment, which programs are to be considered established, and how evaluation cycles would factor into the analysis. This uncertainty is a substantial problem. Mr. Marks states that it provides no clear guidance for interpreting the operative phrase triggering retrospective evaluations: "significant changes — either in the program design or deliver, or changes in the market itself … ." (AG Ex. 1.0 at 40). Mr. Marks states that this burdens the Utilities with unreasonable risks. Mr. Mosenthal's proposal also provides no guidance for how decisions will be made to determine which programs will be subject to retrospective NTG evaluations. Mr. Marks states that, presumably, the decision would lie with the independent evaluator; Staff, stakeholders, and the Utilities could provide input, but, the ultimate decision would rest with the independent evaluator. NS-PGL Ex. 3.0 at 11.

The Utilities support keeping NTG values constant for the entire three-year Plan Period. According to Mr. Marks, many states are taking similar approaches, including the States of California (in a recent policy change recognizing the excessive risk to utilities of NTG estimation error), Iowa, Minnesota, Missouri, New York, and New Jersey. NS-PGL Ex. 3.0 at 11-12.

Mr. Mosenthal cited agreements and orders from other cases in support of his position regarding the NTG issue. AG Ex. 1.0 at 22, lines 21-24. He further states, "I believe the Utilities' NTG proposal is in conflict with both current ICC precedent and the NTG framework established by the SAG… ." AG Ex. 1.0 at 23-24. Mr. Marks states that the SAG to which Mr. Mosenthal refers in this part of his testimony is the electric utility SAG. The gas utilities have yet to implement a single program under the new law. The Utilities state that this proceeding's purpose is to establish the framework for implementing the Utilities' program. An important part of that framework is to determine the best way in which to account for program savings towards meeting the statutory goals. There is not yet a gas utility SAG in Illinois, and Mr. Mosenthal does not explain the relevance of any discussions that occurred among the electric utilities and other electric SAG members. Moreover, Mr. Marks states that some of those discussions occurred over three years ago. Mr. Marks states that the Utilities' Plan is a gas utility portfolio based upon industry best practice, and it should be evaluated on its own merits. NS-PGL Ex. 3.0 at 12.

Mr. Mosenthal contends that the Utilities' "deeming proposal" creates "perverse incentives" and shields them from poor performance. AG Ex. 1.0 at 29. Mr. Mosenthal also generally criticizes the basis for estimating the Utilities' NTG assumptions. AG Ex. 1.0 at 34-36. Mr. Marks explains that there are distinct two issues. The first issue is setting the NTG ratios. The Utilities proposed reasonable and unbiased NTG ratios in their Plan. NS-PGL Ex. 3.0 at 13. The Utilities started with a simple premise that the range of NTG would be between 100% and 70%. The Utilities believe that a measure or program with an NTG ratio below 70% should not be offered. Where market intelligence was available, the Utilities made assumptions that were consistent with this information. Where no market intelligence was available, the Utilities assumed 80% to be a reasonable estimate based upon industry experience. The Utilities assumed that the two direct install programs (multifamily and small business) and the behavioral change program would have no free ridership or spillover (although a reduction would be taken for measure persistence). For the C&I custom rebate program, Mr. Marks states that the Plan is based on a 95% NTG ratio since each project would be reviewed prior to granting any incentive. For C&I prescriptive measures and retro-commissioning, the Plan is based on an 80% NTG ratio. For residential prescriptive furnaces (the key measure in the program), the Plan is based on a 90% NTG ratio for People Gas' service area, based on the Chicagoland experience and trade ally market intelligence, and a much lower 70% for North Shore based on the same sources. For all other residential measures the Plan is based on an 80% NTG ratio. NS-PGL Ex. 1.0 at 22. The Utilities developed these ratios in collaboration with the other Illinois gas utilities. No programs have started and no incentives have been paid. There is no reason for the Utilities to understate these estimates. NS-PGL Ex. 3.0 at 14.

The second and more critical issue is that NTG ratios be held constant for the full Plan Period. Mr. Marks states that all of the attributes that Mr. Mosenthal states would affect NTG ratios (assessment of markets, customers' response to programs, shifts in program design and budgets (AG Ex. 1.0 at 29)) also affect participation levels and attainment of goals. Mr. Mosenthal ignores the fact that attaining the gross saving goals is by far the more difficult and challenging aspect in program implementation. The Utilities' witness Mr. Marks based his conclusion on 20 years of direct implementation experience, managing very large programs. NS-PGL Ex. 3.0 at 14.

Mr. Marks states that, when discussing a specific measure -- high efficiency furnaces (AG Ex. 1.0 at 36-38), Mr. Mosenthal ignores specific Peoples Gas data and instead cites generic EPA data. As states in the Plan, the Utilities had discussions with some of the largest trade allies in the Chicago area. They indicated that very little penetration of high efficiency furnaces was occurring in this area. The Utilities also had the benefit of two years' experience with the Chicagoland Program's experience. The Utilities used this market intelligence in the planning process. Chicagoland has had relatively little participation in Peoples Gas' service area for its residential high efficiency furnace program. This market intelligence is current and service-area specific and, thus, more relevant in estimating NTG ratios then a generic EPA survey. NS-PGL Ex. 3.0 at 16-17.

Mr. Mosenthal states "[i]f the Commission approves the ComEd Settlement, I believe it would be appropriate to adopt the SAG framework as a guidance document for other utility EEPs… ." AG Ex. 1.0 at 41. The Utilities disagree. They were not participants in the ComEd proceeding in which the settlement was developed and have not agreed to it. NS-PGL Ex. 3.0 at 15. The Utilities argue that the settlement is not part of the record in this proceeding, and it would be inappropriate and procedurally erroneous to impose it on the Utilities.

d) Technical Reference Manual

Mr. Mosenthal states "[t]he Utilities (ideally in collaboration with the other Illinois gas and electric utilities) should establish and maintain a Technical Reference Manual that documents in a transparent way how savings are estimated, and supports on-going effective modification and version control." AG Ex. 1.0 at 26. Mr. Crandall recommends that the SAG "provide assistance and be the appropriate forum for the initial review … ." ELPC Ex. 1.0 at 21.

The Utilities support the development of a utility-specific TRM. Mr. Marks states that it is important that the Utilities have the responsibility for developing the TRM since they are accountable for meeting portfolio savings goals and are responsible for portfolio implementation. These responsibilities include the development and maintenance of the TRM, ensuring that it is consistent with the evaluation results from the independent evaluator, and consistent with the EM&V policy guidelines provided by the Commission in this proceeding. Consistent with their roles in other areas of portfolio implementation and evaluation, Staff and stakeholders could provide input to the TRM process, but ultimate responsibility for development should remain with the Utilities. NS-PGL Ex. 3.0 at 16-17.

Further, Mr. Marks states that a separate TRM should exist for each utility and not one statewide TRM. Each utility delivers programs in a unique service territory with unique weather, market and customer characteristics that need to be captured in the algorithms and assumptions documented in the TRM. In addition, each utility uses different programs, planning approaches, tracking systems and independent evaluators. According to Mr. Marks, these differences will determine the appropriate database and variable structure needed to manage the TRM for each utility. NS-PGL Ex. 3.0 at 17.

B. AG's Position

1. Evaluation, Measurement & Verification

Section 8-104 of the Act makes clear that the ratepayer-funded energy efficiency programs provided by Illinois utilities must be cost-effective. 220 ILCS 5/8-104(a). ("It is the policy of the State that natural gas utilities and the Department of Commerce and Economic Opportunity are required to use cost-effective energy efficiency to reduce direct and indirect costs to consumers.") This section of the Act squarely places the burden of proving efficiency measures are cost-effective on the utilities.[46] The only way to ensure that programs are, in fact, cost-effective, for purposes of satisfying the requisite Total Resource Cost ("TRC") calculation requirement of Section 8-104(b) is for the Commission to ensure that the evaluation, measurement and verification of ascribed energy savings is fair, fact-based, open and documented. Ensuring that a utility calculates the inputs to the TRC calculation in a fact-based, flexible and documented manner is a crucial task of the Commission in its evaluation of the PGL/NS Plan. As discussed below, the Utilities' approach to these issues inappropriately shifts the risk of cost-effectiveness onto ratepayers through it request to deem important inputs in therm savings calculations, thereby undermining the goal of using "cost-effective energy efficiency to reduce direct and indirect costs to consumers." 220 ILCS 5/8-104(a).

[46] Section 8-104(b) defines cost-effective as follows: "For purposes of this Section, "energy efficiency" means measures that reduce the amount of energy required to achieve a given end use and "cost-effective" means that the measures satisfy the total resource cost test which, for purposes of this Section, means a standard that is met if, for an investment in energy efficiency, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the measures to the net present value of the total costs as calculated over the lifetime of the measures. The total resource cost test compares the sum of avoided natural gas utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided electric utility costs, to the sum of all incremental costs of end use measures (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side measure, to quantify the net savings obtained by substituting demand-side measures for supply resources. 220 ILCS 5/8-104(b).

2. The Utilities' Proposals to Deem Gross Measure Savings Values and Net-to-Gross Ratios Should Be Rejected.

PGL/NS witness Michael Marks offered a number of troubling proposals concerning program evaluation in his testimony. He recommended that:

1) Gross measure savings should be "deemed" or fixed during the three-year plan. Adjustments, if any, shall be made on a prospective basis beginning with the second three-year plan period; and

2) Net-to-gross ratios shall be "deemed" or fixed for the duration of the plan and adjustments, if any, shall be made on a prospective basis beginning with the second three-year plan period.

PGL/NS Ex. 1.0 at 14-26; Tr. at 47- 48.

Mr. Mosenthal and other witnesses raised a number of concerns with the Utilities' deeming and evaluation recommendations. The most troubling concern relates to the Utilities' deeming proposal for the entire three-year plan period, and more specifically, to the deeming of net-to-gross (NTG) ratios. This is inconsistent with previous discussions between other regulated distribution utilities and the SAG, with the ICC's prior Order for the first three-year plan cycle for the ComEd and Ameren energy efficiency plans[47] and the Commission's recent December 21, 2010 order in the Ameren Illinois energy efficiency plan docket, ICC Docket No. 10-0568 and 10-0570. As noted in Mr. Mosenthal's testimony, although there was never a finalized agreement at the SAG, all parties worked toward an agreement on a common framework for how and when to apply net-to-gross deemed values. The Utilities' proposal diverges significantly from this draft agreement.[48] The latest working draft of the SAG NTG framework (AG Exhibit 1.2) is attached to this Brief as Appendix A. It should be adopted, as opposed to the Utilities' deeming proposals, further discussed below.

3. Gross Savings Values

Gross measure savings refer to the estimated total savings (therms) that will be saved by a particular measure installed, without regard for the total *net* impacts of a program that should be adjusted for things like free riders — those participants who installed a measure but would have installed it without the program. AG Ex. 1.0 at 25. Typically, utilities will track measure installations and gross savings in their database, to be adjusted for things like free riders in the future, to ultimately arrive at the *net* impacts of a program. For all intents and purpose, the Utilities' term "per unit therm savings" is synonymous with gross measure savings. *Id.*

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[47] ICC Orders in Docket Nos. 07-0539, 07-0540 and 07-0541.

[48] Note this agreement was originally worked on by the stakeholders, ComEd, Ameren and DCEO and did not include gas-only utilities. However, the Petitioner has attended SAG meetings on a regular basis and has been aware of this agreement and had the opportunity to suggest modifications to it during the period when it was developed.

Peoples Gas and North Shore are proposing to deem gross measure savings for the full three-year period.[49] A review of NS-PGL Exhibit 1.2 (the Plan) includes an extensive list of measures offered under each proposed program, with little explanation of the basis for the measure values. For example, are the therm savings for all measures listed in this exhibit gross savings or do they include a net-to-gross calculation? It is unclear. While the Company makes a general reference to sources for the deemed savings values[50], no explanation is provided as to what sources contributed to each deemed savings value. *See, e.g.,* NS-PGL Ex. 1.2 at 49. As a result, and given the limited time and resources available for this docket, it is unreasonable to expect these values to be deemed *for a full three years* without a more thorough review, an opportunity to understand the underlying assumptions, and a collaborative discussion of their appropriateness. In addition, Mr. Mosenthal testified that his review of the attachment to Utilities' response to Staff data request JLH 1.04 indicates at least some problems with these assumptions. AG Ex. 1.0 at 25-27. Mr. Mosenthal, who has been an active participant on behalf of the People in the electric SAG, recommended that the ICC only *provisionally deem measure savings values,* and direct that the Utilities address any appropriate modifications with the SAG. He recommended that the ICC lock-in the values for the first plan year (PY1), with the expectation that any appropriate adjustments could be made to be used prospectively starting at the beginning of PY2. In that regard, the People believe that the Commission should direct that:

1. Deemed gross measure savings for measures provided in the Utilities' Ex. 1.2 and JLH 1.04 be approved for PY1 only, and only for "prescriptive" or "standard" measures;

2. No deeming of gross measure savings be permitted for any "custom"[51] measures – a position with which the Utilities appear to agree. NS-PGL Ex. 3.0 at 8-9;

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[49] NS-PGL Ex. Ex. 1.0 at 17 (Marks).

[50] Savings estimates for individual measures or programs have been developed in various manners. This includes calculating impacts using generally accepted engineering algorithms based on a set of reasonable assumptions to input variables, building simulation modeling, and reference to existing data sources where such values have already been calculated. Because of the diversity in equipment and energy consumption patterns across multiple building types and end-uses, there exists a variability in these savings estimates as they relate to program design and target markets, particularly at the planning stage of these programs. With this in mind, each of the savings estimates has been compared to several other sources including those developed by the other gas utilities. A collaborative effort throughout the planning process between the utilities allowed for comparison of the measures and has led to a consistency in approach, even if the saving values differed. Where possible, the use of local references was given priority over the use of data from neighboring states or national data. Some of these references include the Midwest Residential Market Assessment and DSM Potential Study by the Midwest Energy Efficiency Alliance and the existing energy efficiency program run by Chicagoland. A similar approach was taken in the development of project costs used in the analysis and in the development of proposed rebate levels keeping in mind that there are already incentive amounts available from Chicagoland.

[51] Most utility energy efficiency programs encourage customers to adopt efficiency through two general approaches, depending on the measure. Prescriptive or standard measures generally refer to those measures that (1) have

3. There should be an ongoing SAG process to review and adjust measure values following the provisional deeming, and SAG members as well as the Petitioner, its implementers, and evaluators should be able to propose modifications;

4. Ongoing modifications should be adopted no later than at the beginning of the following plan year (June 1) based on establishment of new values in the SAG, and, thereafter, each June 1 based on any appropriate new information; and

5. The Utilities (ideally in collaboration with the other Illinois gas and electric utilities) should establish and maintain a Technical Reference Manual (discussed in more detail later in this Brief) that documents in a transparent way how savings are estimated, and supports on-going effective modification and version control. ELPC witness Geoff Crandall similarly advocated the adoption of a statewide TRM. ELPC Ex. 1.0 at 20.

Initially, at least, there was a lack of clarity on the issue of whether the Utilities are proposing to deem "custom" measures. AG Ex. 1.0 at 27.

For example, for the C&I Custom Program, the Utilities simply projected a gross savings value of 6,000 therms per project. *Id.* Similarly, a value per building or per project of 17,400 therms is shown for retro-commissioning. *Id.* Certainly, deeming these types of projects is not appropriate and would likely result in substantial errors in estimating program impacts. Mr. Mosenthal pointed out that "custom" measures, are highly customized measures or projects in which savings and cost-effectiveness can vary dramatically by customer, the numbers of projects tend to be lower than for prescriptive measures, and specific opportunities and measure equipment and configurations may be highly customized. A good example is modifications to an industrial process that results in significant cost-effective savings for a particular customer, but may not be widely applicable to other customers, or may save a dramatically different amount for a different customer. For custom measures, virtually

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relatively consistent and predictable savings values *on average*, (2) are cost-effective and applicable over a wide range of customers, and (3) are generally promoted through some sort of prescriptive or standard offering — for example, $200 rebate of a residential-sized high efficiency gas furnace — regardless of the customer. This approach makes sense for these widely applicable measures and results in reasonably accurate average savings across a large number of program participants. "Custom" measures, on the other hand, are highly customized measures or projects in which savings and cost-effectiveness can vary dramatically by customer, the numbers of projects tend to be lower than for prescriptive measures, and specific opportunities and measure equipment and configurations may be highly customized. A good example is modifications to an industrial process that results in significant cost-effective savings for a particular customer, but may not be widely applicable to other customers, or may save a dramatically different amount for a different customer. For custom measures, virtually all savings calculations are generally based on standard engineering practice, taking into consideration the specific customer's unique circumstances, and also screened for cost-effectiveness to ensure that the measures pass the Total Resource Cost test.[51]

all savings calculations are generally based on standard engineering practice, taking into consideration the specific customer's unique circumstances, and also screened for cost-effectiveness to ensure that the measures pass the TRC test. AG Ex. 1.0 at 26-27.

In rebuttal testimony, NS-PGL witness Marks stated that these "custom" figures are only to be used as a proxy and do not fall within the Utilities' larger proposal to deem measure savings. NS-PGL Ex. 3.0 at 9. To ensure that no deeming is a part of the custom programs, the Commission should make clear in its Order that the Utilities *not* deem any savings estimates for custom measures. In addition, it should reject the Utilities' deeming of gross values proposal, and enter an order in accordance with the five-point framework described above.

4. Net-to-Gross Ratios

Net-to-gross ("NTG") ratios refer to factors developed through program evaluations to adjust the *gross* savings utilities are tracking to reflect the ultimate *net* impacts of the programs. Gross savings are generally adjusted for free ridership and spillover. AG Ex. 1.0 at 23. Free ridership refers to those program participants who would have installed the efficiency measures on their own. While they are counted in the program data tracking, no *net* savings are actually occurring. Conversely, spillover refers to efficiency measures adopted by customers because of either direct or indirect influence of the program, but who do not formally participate in the program and are therefore not initially counted in the utility tracking system of gross savings. *Id.;* Tr. 48. As a result, spillover can increase net savings beyond the gross savings originally tracked by the utility. AG Ex. 1.0 at 23.

As noted above, the Utilities request authority to prospectively fix or deem values for NTG ratios throughout the three years of the Plan. These values would only be updated in preparation for the next three-year plan. Tr. at 48; NS-PGL Ex. 3.0 at 10. However, as explained by Mr. Mosenthal, NTG ratios are a function of many things, with the most important being program design and implementation procedures, as well as factors specific to particular measures, such as current market saturations and barriers. As a result, a NTG ratio is not some sort of fixed fundamental number that cannot vary. Rather, it can be heavily influenced by utility practices including how it markets programs, how it sets incentive levels, the assistance and "handholding" it offers customers, and numerous other implementation details. *Id.* at 29. During cross examination, NS-PGL witness Marks, in fact, agreed that a number of factors affect the net-to-gross calculation of a measure's savings, including program design, how high or low an incentive level is set, how a program is marketed and contractor behavior in marketing or promoting an efficiency measure. Tr. 49.

Once these NTG values are locked in, perverse incentives are created for the Company that diminish achievement of cost-effective programs. Mr. Mosenthal testified that by holding the Utilities accountable to evaluated results, they have a strong incentive to strive to maximize NTG ratios because they want to get credit for maximum savings and avoid penalties. Under the Utilities' deeming proposal, they would be shielded from the impacts of poor net savings performance. At its worst, deeming can encourage high levels of free ridership; at best, it reduces the incentive for the Utilities to continually assess markets and consider how customers are responding to its programs, and whether shifts in program designs or budgets are appropriate. Given that the Utilities request flexibility to change program designs, modify incentives, and shift resources, PGL and NS should also retain the responsibility to show that it has captured savings of at least the statutory performance goals. Otherwise, the opportunities for gaming the system by making changes based on locked-in values that may no longer be correct can result in poor decision-making and programs that are less cost-effective for ratepayers. AG Ex. 1.0 at 29.

As recommended by AG witness Mosenthal, the best approach to ensuring cost-effective programs is to reconsider deemed parameters at least annually in collaboration with the Stakeholder Advisory Group ("SAG").[52] In addition, because the Utilities are just beginning their first statutory EE plans, deeming of NTG ratios should not be done because there is no evidence the NTG ratios the Utilities propose are based on their specific plans or any studies that would support them. Commission deemed parameters need to be reconsidered at least annually in collaboration with the SAG.

There are many reasons why the Commission should order the Utilities to collaborate with the SAG in the development of measure NTG values, not least of which is the fact that the Utilities simply failed to carry their burden of proving their deeming proposal was reasonable and fact-based. NS-PGL witness Marks discussed the basis for the NTG ratios at page 22 of his testimony, stating that:

> …the Utilities started with a simple premise that the range of NTG would be between 100% and 70%. The Utilities believe that a measure or program with an NTG ratio below 70% should not be offered. Where market intelligence was available, we made assumptions that were consistent with this information. Where no

[52] The Stakeholder Advisory Group ("SAG") was first established by the Commission in ICC Docket Nos. 07-0539 and 07-0540, Ameren and ComEd's petitions for approval of electric energy efficiency plans. The SAG consists of various stakeholders, including Commonwealth Edison Company and the Ameren Illinois Utilities, who have met since 2008 to work with the utilities to reach consensus on issues such as program design and evaluation metrics. In its Orders in ICC Docket Nos. 07-0539 and 07-0540, the Commission stated:

> All parties involved, with the possible exception of Staff, maintain that a Stakeholder Advisory Committee is essential to the success of the Plan. This Commission agrees with ComEd that it should establish a stakeholder process to review ComEd's progress towards achieving the required energy efficiency and demand response goals and to continue strengthening the portfolio. The Stakeholder group's responsibilities include, but are not limited to: reviewing final program designs; establishing agreed-upon performance metrics for measuring portfolio and program performance; reviewing Plan progress against metrics and against statutory goals; reviewing program additions or discontinuations; reviewing new proposed programs for the next program cycle; and reviewing program budget shifts between programs where the change is more than 20%.

ICC Docket No. 07-0539, Order of February 6, 2008 at 24; ICC Docket No. 07-0540, Order of February 6, 2008 at 32. Within the past year, both Nicor Gas Company and Peoples Gas and North Shore Gas representatives have attended various SAG meetings.

> market intelligence was available, we assumed 80% to be a reasonable estimate based upon industry experience.[53]

There are a number of problems with this position. First, Mr. Mosenthal disagreed with the Utilities' contention that measures or programs with an NTG ratio below 70% should not be offered. He called this decision "arbitrary", and stated it is not supported by best practices. Likewise, the Act requires that programs be evaluated based on the total resource cost ("TRC") test. 220 ILCS 5/8-104(b). Many energy efficiency programs can and are very cost-effective with NTG ratios below 70%, according to Mr. Mosenthal. AG Ex. 1.0 at 33.

Second, it appears the Utilities' starting point was simply an *a priori* assumption that all NTG ratios would be no lower than 70%, regardless of what "market intelligence" might be available, or whether this is consistent with the best available data. In short, it appears that the Utilities simply defined NTG ratios as being between 70% and 100%, and then made assumptions consistent with that premise. *Id.*

NS-PGL witness Marks went on to provide an alleged basis for the NTG ratios proposed in some instances. NS-PGL Ex. 1.0 at 22. However, the "basis" in most cases is, again, simply an assumption for which the Utilities have been unable to explain any basis. When asked for any analysis or support for the proposed NTG ratios, and all documents related to the "market intelligence" relied on in AG 2.05 (a), the Utilities responded: "The rationale for the net-to-gross (NTG) assumptions is contained on page 22 of NS-PGL Ex. 1.0." This is the same page referenced above in Mr. Marks' testimony. In other words, it appears that the Utilities have not in fact relied on any "market intelligence," as they failed to provide even a single document or workpaper to show the market data upon which they supposedly relied. In short, support is woefully lacking for the Utilities' proposed NTG ratios, other than the simple assumptions they made. Mr. Mosenthal provided a specific list of assumptions made by the Utilities and detailed the lack of foundation for those assumptions:

1. "The utilities assumed that the two direct install programs (multifamily and small business) and the behavioral change program would have no free ridership or spillover." NS-PGL Ex. 1.0 at 22.

   The only "basis" appears to be that they "assumed" the value of 1.0 NTG, as the Utilities fail to provide any additional support for this assumption. AG Ex. 1.0 at 34.

2. "For the C&I custom rebate program, the Plan is based on a 95% NTG ratio since each project would be reviewed prior to granting any incentive." NS-PGL Ex. 1.0 at 22.

This statement plausibly provides a "basis", however, there is no logical or rational explanation for why the Utilities reviewing a project would somehow change the

[53] NS-PGL Ex. 1.0 (Marks) at 22.

NTG ratio. All custom programs review projects prior to granting incentives, but this has absolutely no bearing on whether a customer is a free rider or not.

In addition, this is an example in which the Utilities clearly did have "market intelligence" they chose to ignore — namely the PY1 ComEd electric C&I custom rebate program evaluation. The Utilities claim that this will be a coordinated program, and the fuel used in a custom program should not have a significant impact on NTG ratios. Given this is the exact same program that PGL/NS will be delivering with ComEd, certainly ComEd's actual evaluated NTG ratio would be much more appropriate. This value is 72%, significantly lower than the Utilities' proposal. AG Ex. 1.0 at 34.

3. "For the C&I prescriptive measures and retrofit-commissioning, the Plan is based on an 80% [default] NTG ratio." NS-PGL Ex. 1.0 at 22.

Again, the Utilities appear to have no "basis" or market intelligence, and are simply assuming a default value. AG Ex. 1.0 at 35.

4. "For residential prescriptive furnaces (the key measure in the program), the Plan is based on a 90% NTG ratio for the People Gas service area, based on the Chicagoland experience and trade ally market intelligence, and a much lower 70% for North Shore Gas based on the same sources." NS-PGL Ex. 1.0 at 22.

These assumptions are supposedly based on the "Chicagoland experience and trade ally market intelligence." However, to my knowledge the Chicagoland experience is not based on actual evaluated results from Chicagoland. Rather, it is likely simply a default assumption once again. While trade allies should have some insight into likely NTG ratios, the Utilities appear unable to provide any additional information whatsoever about what they learned from trade allies. This level of explanation is clearly not sufficient to lock in values for a full 3 years with no ability to support it. In addition, as I discuss below, I believe there is significant market intelligence readily available for this measure that would indicate the Utilities proposed values are much too high. Why the Utilities choose either not to research this information, or to ignore it, is not clear. AG Ex. 1.0 at 35.

5. For all other residential measures the plan is based on an 80% [default] NTG ratio. NS-PGL Ex. 1.0 at 22.

Again, clearly this assumption has no basis in fact, but rather is based on a simple default value. AG Ex. 1.0 at 34-36.

In addition, Mr. Mosenthal identified key concerns with the Utilities' NTG assumption for residential gas furnaces – the key measure for the entire residential sector. AG Ex. 1.0 at 36-38. These identified concerns all argue for the Commission ordering the Utilities to participate in the SAG process recommended by Mr. Mosenthal, so that these important factors affecting the cost-effectiveness calculation can be established in

a collaborative, informed fashion and adjusted on a going forward basis for the variable that Mr. Marks himself admits affect the calculation of the NTG ratios. Tr. at 49.
Yet another reason to reject the Utilities' deeming proposal is that it effectively shifts much of the fundamental performance risk -- that is actually achieving *cost-effective, verifiable savings* -- from the Utilities to their ratepayers. AG Ex. 1.0 at 28. By deeming NTG ratios and measure savings, Peoples Gas and North Shore are simply held to achieving the number of projects and measures that get installed, regardless of whether actual EEP performance meets the performance targets the legislature clearly set out in the Act. The simple fact that the Act imposes both performance targets of specific savings values and penalties to the Utilities for non-performance shows the intent was for this risk to be borne by *the utility*, rather than the customers. *See* 220 ILCS 5/8-104(f). By locking in deemed values for the full period of the plan, the Utilities are not only relieved of much of the performance risk intended to apply to them, but also no longer have as clear and strong incentives to maximize savings. AG Ex. 1.0 at 28-29.

Ironically, PGL/NS witness Marks argued that the ratepayers would bear *more* risk by not deeming NTG ratios. He stated:

> If savings are adjusted downward [based on a change in NTG value], and program spending can be increased to make up for the deficit and meet the statutory goal, then these costs will be passed on to the ratepayers. Thus it is the ratepayer, not the utility or implementation contractor that bears the risk here. Only if the change causes the utility to fail to meet the statutory goal and thus has to pay a penalty will the utility or its contractor bear any risk. Given the size of the statutory goals for the first three years, this is an unlikely outcome.[54]

This logic seems to come from a fundamental belief that is at odds with the legislature's intent and the public interest. Mr. Marks seems to view capturing cost-effective efficiency savings as a *negative* for ratepayers, such that if the Utilities had to work harder to capture cost-effective savings and meet statutory goals the ratepayer would be hurt because it would cost more. However, clearly, if a deemed NTG was locked in under this scenario, the ratepayer would have been hurt more. They would still have paid for the efficiency programs, but in the end would not receive the full energy savings benefits that achievement of the statutory goals strive to create. Mr. Mosenthal likened this analysis to suggesting that a car owner is better off if their mechanic fails to properly fix their car because it would have cost more to do it properly. AG Ex. 1.0 at 30.

Mr. Marks further suggests that the risk to the utility is relatively minor, and only an issue if the goals could not still be captured. He indicates that the statutory goals in the first three years are relatively easy to capture, and that the spending limits are far higher than necessary to achieve the goals. NS-PGL Ex. 1.0 at 21. Thus, he makes clear two points:

[54] NS-PGL Ex. 1.0 at 21.

1. The performance risk faced by the Utilities by not deeming NTG values is low, and apparently not much of a concern for the Utilities during this first three-year plan;

2. Even if it turned out that initial NTG assumptions were poor and evaluations identified much lower values, the Utilities agree that failure to meet the goals is an "unlikely outcome" because the proposed spending levels and statutory savings goals are relatively low.

AG Ex. 1.0 at 31. Clearly, the risk to the Utilities of adopting Mr. Mosenthal's proposed NTG framework is negligible given these realities.

There are still other deficiencies in the Utilities' NTG deeming proposal. The Utilities proposal to choose 80% as a default NTG value where no "market intelligence" was available. NS-PGL Ex. 1.0 at 22. However, this is exactly the approach and NTG-value the ICC rejected in its Order in the 2007 electric EEP dockets because it did not reflect actual data about the specific program, market, or Illinois territory. Specifically, three years ago, the issue of deeming NTG ratios was litigated in Dockets 07-0539, 07-0540, and 07-0541, related to the first three-year plans for the electric EEPs. The ICC in its Order in these dockets declined to deem NTG ratios, and determined that utilities should estimate for planning purposes NTG ratios that are most realistic based on review of similar efforts in the Midwest and in consultation with its evaluation contractors, but that NTG ratio estimates from evaluations should be used retroactively until some program experience is developed.[55]

NS-PGL witness Marks claims that decisions made regarding the electric side of energy efficiency in Illinois are irrelevant on the gas side. NS-PGL Ex. 3.0 at 12. The People could not disagree more. While the SAG NTG Framework that was developed by parties focused on the electric EEP's second three-year plan, the Utilities' proposed EEP is completely analogous to the issues the ICC considered in 2007.[56] As pointed out by Mr. Mosenthal, the similarly relevant issues are:

1. This is the first three-year plan, and as such there is the highest level of uncertainty about utility performance and capability, and the ultimate appropriate NTG ratios;

[55] See, for example, ICC Final Illinois Commerce Commission Order in ComEd's ""Commonwealth Edison Company Petition for Approval of the Energy Efficiency and Demand-Response Plan pursuant to Section 12-103(f) of the Public Utilities Act", Docket No. 07-0540, February 6, 2008 at 44 (hereinafter referred to as the "Order").

[56] Although the initial NTG framework is applicable in the instant docket, it is important to note that the SAG has moved somewhat beyond the initial situation the ICC was dealing with in 2007— where no programs had yet begun or been evaluated.

2. Because the goals are relatively low during the first three-year plan, and budgets are not constrained, there is ample time and opportunity for the Utilities to hedge against risk, possibly striving to increase savings and participation as a buffer and also to adjust its programs after some early evaluation or other study results, if appropriate; and

3. There appears to be little basis for the NTG ratios proposed, with many of them based on the Utilities' simple premise that NTG ratios should range between 70 and 100 percent. Where no additional "market intelligence is available," the Utilities assumed an 80 percent default NTG ratio, specifically what the ICC rejected in its 2007 Order.[57]

AG Ex. 1.0 at 32.

PGL/NS witness Marks complained that "[w]ithout certainty on the amount of savings, [implementation contractors] will be credited with for each measure they deliver, a performance based contract becomes too risky for the implementation contractor."[58] However, as noted by Mr. Mosenthal, the Utilities' response to ELPC 1.05 shows that there are many ways one could still sign a performance contract with its EE program implementer, Franklin Energy Services. For example, the contract could specify gross therms, holding Franklin to gross savings performance and the Utilities' absorbing any NTG risk. In fact, the response states that Franklin is "indifferent to the deemed savings" because in the end the math ultimately just reduces the "specific participation goals."[59] Clearly the Utilities could simply develop participation goals as a performance metric as well. The difference is simply that the Utilities desire to shed *all* of their risk, even though they acknowledge this risk is minor and could only result from an "unlikely outcome." While Mr. Mosenthal testified that he generally supports performance contracting, it is hardly in the best interest of PGL/NS ratepayers for the Utilities to shift all of the risk onto its customers. Yet, the Utilities' deeming and NTG proposals do just that.

For all of these reasons, the Utilities' proposal to deem NTG values should be rejected. Instead, the Commission should adopt the SAG NTG framework, as described below.

5. The SAG NTG Framework Should Be Adopted

As mentioned above, in collaboration with Ameren, ComEd and DCEO stakeholders developed a tentative agreement for deeming NTG ratios that would provide the utilities significantly reduced risk, while still preserving incentives for utilities to strive to maximize NTG ratios and make appropriate mid-course corrections. Because many of the electric programs have already been evaluated, this provides some certainty to utilities on savings claims for those programs that

[57] NS-PGL Ex. 1.0 at 22 (Marks).
[58] NS-PGL Ex. 1.0 at 25 (Marks).
[59] PGL-NS Response to ELPC 1.05.

have evaluated results, which can be deemed until new values are available for prospective use.

1. Where a program design and its delivery methods are relatively stable over time, *and* an Illinois evaluation of that program has estimated a NTG ratio, that ratio can be used *prospectively* until a new evaluation estimates a new NTG ratio.

2. In cases that fall under #1 above, once new evaluation results exist, these would be used going forward, *to be applied in subsequent program years following their determination* until the next evaluation, and so on.

3. For existing and new programs not yet evaluated, and previously evaluated programs undergoing significant changes — either in the program design or delivery, or changes in the market itself[60] — NTG ratios established through evaluations would be used *retroactively*, but could also then be used prospectively if the program does not undergo continued significant changes, similar to #1 above.

4. For programs falling under #3, deeming a NTG ratio *prospectively*, may be appropriate if: the program design and market are understood well enough to reasonably accurately estimate an initial NTG *(e.g.,* based on evaluated programs elsewhere); <u>or</u> it is determined that the savings and benefits of the program are not sufficient to devote the evaluation resources necessary to better estimate a NTG ratio.

5. The SAG will recommend to the Commission, in advance of the evaluation study start date, whether the NTG values resulting from the evaluation study should be applied in the year they are determined (due to significant program, technological, market changes, or other factors) or only in the following program year.

AG Ex. 1.2 at 2, 3.

The above framework achieves four things. First, it provides some certainty of savings claims for Program Administrators ("PAs") for the *majority* of their portfolio savings, thus dramatically reducing short term performance risk. For example, the Residential lighting and C&I Prescriptive lighting programs at this point provide the vast majority of portfolio savings, have not undergone significant changes since PY1, and have been evaluated.

Second, it continues to provide a strong — albeit diminished — incentive for PAs to work to maximize NTG ratios and net savings by continually doing the necessary research to understand markets and make program changes as appropriate in a timely fashion. This is because, while current savings may be counted on a "NTG deemed" basis, future evaluations that find a significantly diminished NTG ratio will increase PA challenges to meet future goals. Thus, longer term the PAs are still served best by minimizing free riders.

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[60] An example of a market change might be where baselines have improved significantly and the likely free riders are growing substantially because of it.

Third, it ensures that decisions about new initiatives or significant program changes are made recognizing and balancing performance risk as part of the overall portfolio. This provides PAs with an incentive to design and deliver these programs to minimize free riders initially, and be held accountable for results. Thus, PAs can experiment with innovative strategies (since these will represent a minority of portfolio savings, significant flexibility and hedging ability will exist) while not encouraging program designs or delivery strategies that are likely to have very high freeridership or questionable cost-effectiveness.

Finally, it provides a mechanism to manage evaluation resources to ensure they are spent most effectively, and on those areas with the greatest impact and/or uncertainty. AG Ex. 1.2 at 2-3.

The SAG framework was never *formally* agreed to by all parties. It is, however, adopted as part of the proposed settlement in ComEd Docket No. 10-0570 related to its second three-year electric plan. As noted above, a copy of the latest working draft of the NTG framework, AG Exhibit 1.3, is attached as Appendix A to this Brief.

As noted by Mr. Mosenthal, the framework developed was a reasonable approach at balancing utility risk, ratepayer risk, accuracy, and the need to focus EM&V resources on those areas where they are most useful. In orders issued on December 21, 2010, the Commission ordered the adoption of the NTG Framework for purposes of developing these ratios in the ComEd and Ameren programs. *See,* e.g. ICC Docket No. 10-0568, Order of December 21, 2010 at 70.[61] There is no reason to treat the gas utility programs any differently when it comes to ensuring consistent, fact-based and verifiable inputs into the TRC calculation. The SAG framework provides a balanced approach that allows for deeming of NTG ratios once some reliable and relevant data about the program is developed, while also ensuring that ratepayers get what they pay for.

As noted by Mr. Mosenthal, even the Utilities have acknowledged its risk of not achieving the statutory savings goals is small.[62] He testified that NTG-related risks can only be managed with imperfect information. For example, under a retroactive framework the Utilities cannot know the ultimate NTG ratio to which it will be held. However, all else being held equal, the Utilities and their implementation contractors still have many day-to-day implementation and program design decisions that can influence NTG ratios, and can be managed to optimize NTG ratios. Just as students cannot know what grade they will receive from a teacher in advance, they can still manage the risk by performing at a high level and trusting that, all else being equal, the better the student’s efforts, the higher their final grade will be. As a result, holding the utilities accountable for actual NTG ratios, even if applied retroactively, provides the Utilities with the correct incentives — namely, to strive for the best possible outcome.

[61] At the Open Meeting, Chairman Flores specifically moved that the Order be amended to adopt the NTG framework and the creation of a statewide TRM. The motion carried, with three commissioners voting yes and two commissioners abstaining. No transcript has yet been filed on e-Docket of the meeting. The People have filed a motion seeking clarification of this decision in the Ameren (10-0568) Order, which includes some contradictory language on the point.

[62] NS-PGL Ex. 1.0 at 21 (Marks).

The Utilities argued that because of this performance-based contract, and to effectively manage such a contractual relationship, it is critical to have the ability to track performance in "real time", and that if impacts are changed midstream, the implementation contractor cannot know how well they are doing in meeting goals and thus cannot manage their costs. NS-PGL Ex. 1.0 at 25. Without certainty on the amount of savings they will be credited with for each measure they deliver, a performance based contract becomes too risky for the implementation contractor, according to the Utilities. *Id.* These concerns about evaluation cycles, timing and budget constraints are strawman arguments. Mr. Mosenthal noted that while impact evaluation studies would lag programs by at least one year, and therefore would not produce results until the end of 2012, the Utilities would still have ample opportunities to initiate mid-course corrections. As a result, the Utilities should be able to easily adjust their programs and spending to achieve their savings goals. Further, Mr. Mosenthal disagreed that full blown and expensive impact evaluations are necessary to reasonably estimate NTG ratios. He noted that a participant survey, for example, could be done for something like gas furnaces (perhaps the most uncertain NTG ratio with the biggest potential impact) even after six months of program delivery and be available prior to even PY2 at relatively modest cost. At that point, about 83% of the three-year savings goals would still be planned for future program years. AG Ex. 1.0 at 42.

Finally, because the goals are relatively low for the first three-year period and funds are more than sufficient, the Utilities have acknowledged it should be able to easily over-achieve goals somewhat to hedge against a surprisingly low NTG ratio estimate.[63] Even if this overachievement turned out to be unnecessary to meet goals, the additional cost-effective savings would offer ratepayers greater net benefits while still ensuring spending under the rate caps.

In sum, the People urge the Commission to reject the Utilities' proposed deemed Gross Savings and NTG ratios. The Utilities have not provided any sufficient explanation to support these proposed values as particularly likely for its programs or measures. Instead, the Commission should adopt the basic framework established by the SAG and the primary guidance and principles behind appropriate NTG treatment. Under this approach, the Commission should order the Utilities to work with the SAG to establish a high level evaluation plan that identifies what NTG values will be measured, when results would be available, and how they would be used prospectively in terms of starting dates and duration. Under this approach, the SAG would also be free to agree to propose to the Utilities deeming a NTG value based on currently available information, and forego evaluation of NTG ratios for a particular program or measure if it agreed that the resources necessary to refine the estimate were not justified based on EM&V resources, uncertainty, and the level of ultimate likely impact.

[63] NS-PGL Ex. 1.0 at 21 (Marks).

6. Technical Resource Manual

Some jurisdictions maintain a set of algorithms that define all parameters involved in estimating measure savings rather than simply a table of kWh/year or therms/year. In this Order referred to by the acronym TRM. Both AG witness Mosenthal and ELPC witness Crandall recommended the Commission adopt a TRM. AG Ex. 1.0 at 26*;* ELPC Ex. 1.0 at 15. The People urge the Commission to direct the Utilities (along with the other gas and electric utilities) to develop a statewide TRM. This is important for transparency of EE measure assumptions, documentation of savings achieved, ease of on-going modifications and version control, and consistency. Such statewide manuals have been developed in Pennsylvania, Ohio, Michigan and other states. ELPC Ex. 1.0 at 20.

As explained by Mr. Crandall, the TRM would include a wide array of information on the details of natural gas and electric energy efficiency and demand response measures and programs. *Id.* This typically includes: cost of measures, cost of installation, savings estimates in terms of estimated therms, kWh, KWs. In addition the TRM would include measures costs, useful life estimates for program measures, estimated realization rates, net-to-gross, "deemed" savings estimates for planning purposes and similar information. The energy efficiency program developers, implementers and evaluation contractors would use the TRM values for developing and modifying programs as well as the initial process or impact analyses to be done throughout the state. Spelling out clear assumptions and parameters in a TRM provides stakeholders and the ICC with greater transparency, and provides a single place where all assumptions are documented. These assumptions can vary by utility where appropriate, for example because of weather variations.

This approach allows easier global adjustments and on-going modifications, and allows for proper documentation of what changed and when. This is critical for evaluators and prudency reviews, since the deeming process permits certain values to be used only for specific periods, and then requires different values to be adopted by a certain date. Establishing a TRM that clearly documents effective dates and has good version control will go a long way to improving utility data accuracy and facilitating critical review of data.

Finally, adopting a TRM would facilitate a much more open, clear, productive, and well-documented SAG review and modification of deemed values. For all of these reasons, the Commission should require the Utilities to participate in a statewide development of a TRM. It should be noted that the Commission stated orally on December 21, 2010 that it would mandate the development by both ComEd and Ameren of a statewide TRM. ICC Docket Nos. 10-0568, 10-0570. (The People have pending a Motion to Clarify that Order.) All utilities (and ratepayers) would benefit from the creation of such a manual, and it should be ordered in this docket at well.

7. Evaluation Cycle

The Utilities propose that an independent evaluator conduct at least one impact evaluation and one process evaluation for each program during the three-year Plan. NS-PGL Ex. 3.0 at 4-5. The People object to this proposal. As noted by Mr. Mosenthal, at this point the Utilities' recommendation is premature because it is too prescriptive and could result in a poor allocation of limited EM&V funds. AG Ex. 1.0 at 43. Fundamentally, limited EM&V funds should be allocated where and when they are most useful. This determination should consider things such as, but not limited to:

- How new is the program?
- How much of the Utilities' resources are being expended on a given program?
- When did the program start?
- Is the program expected to be continued for a long time or be phased out?
- What share of the portfolio impacts come from the program?
- How uncertain are a particular program's impacts, and how big is that uncertainty relative to the overall portfolio savings?
- Is the program a new, complex delivery system, such that an early process evaluation is warranted?
- Are the market and program well understood, and are reasonable values such as NTG ratios known with reasonable certainty from other jurisdictions or publicly available studies or data?
- Is the market very dynamic and changing rapidly enough to warrant two evaluations during a single plan period?

Id. at 44.

While the above is not a comprehensive list, the point is that planning only for large, expensive and very time-consuming evaluations and not allowing flexibility for smaller studies may further constrain these resource decisions. Also, automatically engaging in impact evaluations on every program once and only once may not result in the optimal allocation of these scarce resources. For example, Mr. Mosenthal noted that perhaps more resources should be focused early on for process evaluations in lieu of some impact evaluations. Often an "early-look, mini-process evaluation" can be very important in the first year to assess whether implementation procedures are working as expected and whether the Utilities, their contractor network and data systems are working properly. Also, Mr. Mosenthal testified that he would expect that some early attention to process assessments of the effectiveness of joint and cooperative programs may be important (with funding shared by PGL/NS and ComEd or other program administrators). *Id.* at 44.

To be clear, at issue is not how many evaluations should occur. Rather, the 3% limit (220- ILCS 5/8-104(f)(8)) on evaluation spending supports targeting resources where they provide the greatest overall value. However, as noted above, correcting the Utilities' erroneous interpretation of how to calculate the statutory savings goals and spending caps will provide roughly three times greater evaluation funds, which will go a long way to offset this resource problem. Section 8-104(f)(8) of the Act allows the Utilities to treat their full three-year evaluation budget as a single cumulative limit, rather than constraining each year to only 3% of each year's budget. 220 ILCS 5/8-104(f)(8).

Managing limited evaluation resources may require trade-offs between important objectives. One objective is to provide the ICC and ratepayers with adequate assurance that the Utilities' programs are indeed providing the net savings that ratepayers are paying for, and are doing so efficiently and effectively. Another objective is for the Utilities and their contractors to learn from evaluations about ways the programs can be improved, what is working well and what is not. Rather than prescribe specific evaluation activity now, the ICC should direct the Utilities to work with the SAG and evaluation contractor(s) (as ComEd and Ameren have effectively done over the past three years) to develop a thoughtful and reasoned EM&V planning process that considers trade-offs and resource limitations, and that makes the most of the limited funds available. In concert with the evaluation contractors, the Utilities and the SAG should explore these trade-offs and work together to develop EM&V high-level plans. This was done as part of the SAG with the electric utilities' first three-year evaluation plan and should be continued on the gas side.

Mr. Mosenthal noted, too, that there may well be instances where joint statewide evaluations make sense. Specifically, for programs delivered jointly with ComEd, the Utilities and ComEd should strive to implement joint evaluations. PGL/NS have indicated their plans to pursue joint evaluations with ComEd and I support that decision.[64] There may also be gas efficiency programs similar enough between PGL/NS, Nicor, and Ameren to justify some joint evaluations. Joint evaluations should be pursued where they offer economies of scale and can provide consistent methodologies and provide results to compare across territories.

The People urge the ICC to direct that the Utilities, in collaboration with the SAG, develop evaluation plans that strive to maximize benefits by combining evaluation efforts wherever possible and appropriate across any combinations of gas and electric utility jurisdictions where programs are similar or jointly offered.

C. CUB-CITY's Position

1. The Utilities' Evaluation Plan

The PUA specifies that gas utility plans:

> (8) Provide for quarterly status reports tracking implementation of and expenditures for the utility's portfolio of measures and the Department's portfolio of measures, *an annual independent review, and a full independent evaluation of the 3-year results of the performance and the*

[64] NS-PGL Ex. at 9 (Marks).

> *cost-effectiveness of the utility's and Department's portfolios of measures and broader net program impacts* and, to the extent practical, for adjustment of the measures on a going forward basis as a result of the evaluations. The resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given 3-year period. (Emphasis added). 220 ILCS 5/8-104(f).

The testimony of Michael Marks explained the Utilities' EM&V framework. The Utilities have hired Navigant Consulting ("Navigant") as an independent evaluator. Navigant will conduct one comprehensive impact evaluator per program during the three Plan years,[65] including at least one impact evaluation and one process evaluation, per program, during the Plan period.[66] The Utilities' Plan defines a process evaluation as one that "focuses on the effectiveness of program delivery, marketing, achievement of participation goals, customer satisfaction and other qualitative (non-therm) goals."[67] An impact evaluation "is primarily concerned with measuring the therm savings that programs achieve. This can include estimating net-to-gross ("NTG") ratios (free ridership and spillover), if such estimates can be determined with reasonable accuracy at a reasonable cost. Impact evaluation would ensure that measure level estimates of energy savings are made consistently with the approved methodologies."[68]

The General Assembly has explicitly directed that the utility and its evaluator be separate. CUB/City want to ensure that separation is in place. It is important that the Utilities' evaluator is independent. The Commission has previously discussed this point in Docket Nos. 07-0539 and 07-0540, approving Ameren and ComEd's energy efficiency and demand response plans. On rehearing, the Commission explicitly addressed the process by which the statutory goals of an independent evaluation could be achieved – the same goals contained in Section 8-104 of the Act. The Commission noted the General Assembly's articulated goal of reducing the delivery load the electric utilities would be impeded "unnecessarily" if the Commission was engaged in the day-to-day activities of the hiring of the independent evaluators.[69] In order to make sure the programs could begin in a timely fashion, the Commission concluded that the evaluator would not be "independent," as required by statute, if the utility had total control over that evaluator. Rather than designing an RFP and undertaking the selection process for an evaluator, the Commission assumed a supervisory capacity regarding the hiring and firing of the evaluator, meaning that the utility must gain Commission consent to make the hiring and firing decisions regarding the evaluator.

Based on the Commission's previous recommendations regarding an independent evaluator, the Commission should monitor the Utilities' evaluation process to ensure that Navigant is an independent evaluator.

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[65] NS-PGL Ex. 1.0 at 14.
[66] NS-PGL Ex. 3.0 at 4-5.
[67] NS-PGL Ex. 1.2 at 23.
[68] *Id.*

[69] Final Order on Rehearing, ICC Dockets No. 07-0539 and 07-0540, at 3 (March 26, 2008).

2. Fixed Values and Net to Gross

The Utilities' proposal for EM&V, is to "deem" or fix gross measure savings for its entire three-year Plan.[70] The Utilities plan to only make adjustments prospectively; "in other words, evaluation results would be applied to future deemed values in the next three-year planning period, and not used to adjust the deemed values approved in this filing."[71] These deemed ratios include NTG ratios.[72] NTG ratios are factors developed through program evaluations to adjust the gross savings utilities are tracking to reflect the ultimate net impacts of the programs.[73] Gross savings are usually adjusted for free ridership (those program participants who would have installed the efficiency measures on their own) and spillover (efficiency measures adopted by customers because of either direct or indirect influence of the program but without formal program participation).[74] AG witness Mr. Marks recommends that the Commission use "best available" estimates for NTG ratios and approve deemed values for the Utilities three-year Plan in order to remain consistent with previous electric plan filings.[75]

Because of the importance the General Assembly has placed on counting the net savings achieved by utilities, and the need to ensure ratepayer dollars are spent on bringing actual benefits to customers, environmental and consumer intervenors in the case opposed the Utilities' proposal.

As Mr. Mosenthal explained, the Utilities' proposal "is neither consistent with previous discussions between other regulated distribution utilities and the SAG nor with the ICC's prior Order for the first three-year plan cycle for the ComEd, Ameren and DCEO electric EEPs."[76] The NTG framework proposed by the Utilities conflicts with ICC precedent and the SAG NTG framework[77]

CUB/City, the AG, and ELPC disagree with the Utilities' proposal to deem values for the entire three-year Plan period. Doing so creates perverse incentives that shield the Utilities from impacts of poor net savings performance, and can encourage high levels of free ridership. At best, it reduces the Utilities' incentive to continually assess markets and consider how customers are responding to its programs, informing the utilities whether to modify program designs or budgets if appropriate.[78] Mr. Mosenthal reiterated how important NTG ratios can be, including program design and implementation procedures, meaning that "as a result, a NTG ratio is not some sort of fixed fundamental number that cannot vary."[79]

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[70] NS-PGL Ex. 1.0 at 15.
[71] *Id.* at 17.
[72] *Id.*
[73] CITE
[74] AG Ex. 1.0 at 23.
[75] *Id.* at 20.
[76] *Id.* at 22.
[77] *Id.* at 23-24.
[78] AG Ex. 1.0 at 29.
[79] *Id.*

CUB/City agree with Mr. Mosenthal's recommendation to hold the Utilities accountable for actual NTG ratios, even if applied retroactively, in order to provide the Utilities with the correct incentives – namely, to strive for the best possible outcome.[80] It is not in the public interest to allow the Utilities to deem values for their entire three-year Plan. If the Commission allows the Utilities to deem values in this way, the incentive to manage programs carefully to achieve maximum energy savings dwindles. Mr. Mosenthal recommended the Commission adopt the NTG Framework developed by the electric energy efficiency SAG. The electric SAG's Framework was developed between Ameren, ComEd, and DCEO, and SAG participants such as the AG, ELPC and CUB. It calls for applying NTG ratios on a prospective basis as they become available from program evaluations.[81] Mr. Mosenthal recommended that the ICC reject the Utilities' proposal to deem NTG ratios for all three-years of their Plan, and adopt the electric SAG NTG framework. Related to the SAG framework, Mr. Mosenthal recommended that the gas SAG work with the Utilities to establish a high level evaluation plan that identifies what NTG values will be measured, when results would be available, and how they would be used prospectively in terms of starting dates and duration.[82] CUB/City support Mosenthal's recommendations.

ComEd agreed to follow the SAG NTG framework as part of the settlement it reached with other parties in Docket No. 10-0570.[83] Additionally, Ameren was ordered by the Commission to adopt the SAG NTG framework in ICC Docket No. 10-0568.[84] The Utilities recognize the importance of consistency between utilities on this issue. In rebuttal testimony, Mr. Marks explained that the Utilities worked with Ameren and Nicor on EM&V, stating that a compatible approach between utilities "can benefit the Commission in its oversight role and simplify stakeholders‘ ability to fulfill their advisory roles. It also helps the gas utilities by providing a common platform from which to measure program performance."[85]

The State of Illinois is best served when there are consistent policies across utilities on deemed parameters such as NTG, realization rates, and gross measure savings. CUB/City agree with AG witness Mosenthal's assessment of NTG ratios as detailed above. The Commission should order the Utilities to adopt the electric SAG NTG framework.

3. Experimental Design Analysis

The Commission should order that the Utilities' independent evaluators apply what the California Manual refers to as "Experimental Design," which provides a transparent framework and minimizes evaluation costs at scale, to both People Gas's and North Shore's residential behavior change program and other programs as

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[80] *Id.* at 41.
[81] *Id.* at 40.
[82] *Id.* at 42-43.
[83] *Id.* at 40.
[84] CITE
[85] NS-PGL Ex. 3.0 at 4.

appropriate, instead of the simple surveys proposed by the Utilities in their Plan.[86] The Commission recently adopted this recommendation in its 10-0568 Order, [87] and should do the same in this docket.

Experimental Design is a methodology that analyzes the electricity usage of program participants compared to a control group to determine actual energy savings based on meter data that normalizes for all relevant exogenous factors affecting energy usage.[88] Because the evaluation mechanism is custom fit to the individual program, Experimental Design, recognized as a superior form of EM&V, significantly increases the accuracy of electricity savings, with the added advantage of tracking savings on a regular basis for purposes of truing-up incentives by including the following conditions:

- Trackable program participation;
- Standard statistical parameters for measuring electricity savings;
- Robust control group parameters; and
- No double-counting of savings claimed by other programs, such as traditional deemed savings programs.[89]

As CUB/City witness Mr. Thomas explained, in order to appropriately apply Experimental Design, participant sample size parameters should be standardized. This can be done simply through a centralized program tracking database that allows an independent evaluator to net out savings claimed by traditional programs.[90]

The Commission should require that Peoples Gas's and North Shore's independent evaluator work with the newly created natural gas SAG to develop Experimental Design guidelines and ensure transparent and consistent methods for determining electricity and natural gas savings.[91] The evaluator should maintain a master database of participation, billing, and control group data to ensure savings are verified in an independent and timely manner.[92] The costs involved with exporting the appropriate data to the independent evaluator must be controlled by the Utilities so that the costs do not exceed the 3% EM&V threshold included in Section 8-104 of the PUA.[93]

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[86] CUB/City Ex. 1.0 at 20-22.

[87] ICC Docket 10-0568 Final Order at 88.

[88] CUB/City Ex. 1.0 at 22.

[89] *Id.* at 22-23.

[90] *Id.* at 23.

[91] *Id.*

[92] *Id.*

[93] *Id.*

The use of behavior change programs in promoting energy efficient behavior among residential customers, in particular the role third-party administrators can play in fostering innovative program design and the potential use of Experimental Design protocols to evaluate those types of program, is an important consideration that the Utilities should take to their independent evaluator. The Commission should order the Utilities to provide information on the Experimental Design methodology to their evaluator for the Utilities' behavior change pilot program and other programs, as appropriate.

D. ELPC's Position on Evaluation, Measurement and Verification

In order to determine whether the NS-PGL Plan complies with the PUA, the Commission must be able to determine the energy savings from the programs and the cost-effectiveness of the programs. *See* 220 ILCS 5/8-104(f). These calculations depend on a number of assumptions, including the savings per unit, the expected life of the measure, the utility's "avoided cost", and the net-to-gross ("NTG") ratio for the program. Typically utilities and commissions use engineering estimates or examples from other jurisdictions to estimate or "deem" some of these assumptions in early years of a program. However, the Commission must have confidence in the process for reviewing, verifying, and updating these assumptions, or it can have little confidence in the overall level of savings and cost-effectiveness of a program.

In this case, several witnesses have expressed concern about the quality of inputs and assumptions in the NS-PGL plan and the process the Utilities propose using to verify and update them. As described below, the Commission should reject the Utilities' proposals to lock-in deemed savings values for the full 3-year plan period and should require the company to cooperate with an Illinois natural gas stakeholder advisory group (SAG) to develop a technical resource manual (TRM) to ensure transparency and consistency of assumptions.

1. The Utilities' Proposal to "Lock-In" NTG Ratios and Other Deemed Input Values For Three Years is Not Reasonable and Conflicts With Prior Commission Precedent.

Company witness Marks recommends that gross measure savings and net-to-gross ratios be "deemed" or fixed during the three-year plan period. Adjustments, if any, shall be made on a prospective basis beginning with the second three-year plan period. NS-PGL Ex. 1.0, 14-26. This is not a reasonable approach. As explained in ELPC witness Crandall and AG witness Mosenthal testimonies, the Utilities have not sufficiently justified why they need key program assumptions like NTG to remain locked in for the entire life of the Plans. The Utilities are spending ratepayer funds on these programs and the Commission should do what it can to ensure these programs produce savings. Ratepayers shouldn't have to wait three years for the Company to make adjustments. *See* AG Ex. 1.0, 22; ELPC Ex. 1.0, 21-22.

Mr. Mosenthal further explains that deeming NTG ratios for the entire three years of the plan effectively shifts much of the fundamental performance risk of its EEP from each Company to its ratepayers:

> Underperformance hurts ratepayers directly. By locking in deemed values for the full period of the plan, the Utilities are not only relieved of much of the performance risk intended to apply to them, but also no longer have as clear and strong incentives to maximize savings.

AG Ex. 1.0, 29. Mr. Crandall similarly observes that there may be incentives for the Utilities and their implementation contractors to overstate deemed savings values:

> By having deemed values that overstate the actual savings, the actual savings will be less than the savings with which both the implementation contractor and Utilities are credited. The implementation contractor and the Utilities benefit, but the customers do not.

ELPC Ex. 1.0, 12.

A better approach, according to Mr. Mosenthal and Mr. Crandall, is to provisionally deem input values, but create a process that would allow the values to be updated on a prospective basis soon after EM&V study results are known. *See* AG Ex. 1.0, 24-26; ELPC Ex. 1.0, 22. Both witnesses recommend that the Commission reject the Utilities' proposal and adopt the basic framework established by the Illinois stakeholder advisory group (SAG). AG Ex. 1.0, 42. In general, this framework allows NTG values to be deemed prospectively for stable programs. Once new evaluation results exist, these can be applied to subsequent program years. For new programs or those undergoing significant changes, the framework calls for NTG ratios to be used *retroactively* unless the "program design and market are understood well enough to reasonably accurately estimate an initial NTG" or it is determined that the program is too small to devote evaluation resources towards estimating a more accurate NTG ratio. *See* AG Ex. 1.3. According to Mr. Mosenthal, this framework "would provide the utilities significantly reduced risk, while still preserving incentives for utilities to strive to maximize NTG ratios and make appropriate mid-course corrections." AG Ex. 1.0, 40.

In the last round of electric EE planning cases, the Commission rejected proposals from ComEd and Ameren to fix NTG ratios for three years:

> … there is no indication, from the evidence provided, that the Net to Gross ratios that ComEd seeks to have this Commission "deem" are accurate or applicable. We conclude that ComEd's program should contain actual Net to Gross ratios. We, therefore, decline to "deem" ComEd's Net to Gross ratios. We encourage ComEd to work with its EM&V Evaluator to develop Net to Gross ratios using any information it has, as well as, information available regarding other Midwestern states …

ICC Docket 07-0540, Final Order at 44; *see also* Docket No. 07-0539, Final Order at 33.

In the current ComEd case, the Commission "commend[ed] the stakeholders for having established the NTG framework in the SAG" and noted the "widespread consensus regarding this framework." Case No. 10-0570, Final Order at 47. Furthermore, it is our understanding that the Commission at its December 21, 2010 bench session agreed to adopt the SAG framework in the Ameren Final Order (Case No. 10-0568). Although these edits did not appear in the Ameren Final Order, the Attorney General, ELPC and NRDC have filed a Motion for Clarification requesting the Commission to make this change to assure that the Final Order is consistent with the Commission's action and voting record decided on December 21, 2010.[94]

The Commission should take similar action here to ensure consistency in the evaluation process for Illinois utilities and stakeholders.

2. The Utilities Should Verify the Accuracy of Their Avoided Cost Calculations

In his testimony ELPC witness Geoff Crandall raised concerns about the adequacy of the Utilities' methods for calculating avoided costs. For example, Mr. Crandall identified a contradiction in how the Company described its avoided cost formula:

> The Utilities in their plan, NS-PGL Exhibit 1.2 stated that the avoided costs included the "reduction in transmission, distribution, commodity and capacity costs." (page 20) In response to ELPC Data Request1.16, the Utilities provided the numeric values for commodity and capacity costs without documentation, and then added, "Note that avoided costs do not include any transmission or distribution costs." The response to ELPC Data Request1.16 is in contradiction to their filed plan.

ELPC Ex. 1.0, 16. If the Utilities excluded transmission and distribution costs, then their calculated avoided costs would be too low. This would make the Utilities' measures and programs appear less cost-effective than they actually are. *Id.* at 17.

More broadly, Mr. Crandall is concerned that "there is still insufficient documentation of the Utilities avoided cost methods and data to determine the reasonableness of the approach." *Id.* at 16. The Commission should require the Utilities to review and verify their avoided cost calculations and provide additional documentation to stakeholders to allow them to meaningfully assess the Utilities' approach.

3. The Commission Should Direct The Utilities to Participate in a Statewide SAG for Natural Gas Efficiency Programs.

The intervenors' testimony identifies a number of areas where the Utilities could reduce administrative costs and improve results by coordinating with other utilities and stakeholders. *See, e.g.,* AG Ex. 1.0, 49-53; ELPC Ex. 1.0, 18-19; CUB Ex. 1.0, 25.

[94] Docket No. 10-0568, Motion for Clarification or in the Alternative Application for Rehearing, Jan. 4, 2011.

These and other similar issues could be discussed and implemented through a statewide SAG process similar to the one that has been in place for electric efficiency programs. Most parties support the creation of a natural gas SAG. *See* ELPC Ex. 1.0, 17; AG Ex. 1.0, 45-46; CUB Ex. 1.0, 28. The Utilities do not oppose a gas SAG as long as it is "advisory." *See* NS-PGL Ex. 3.0, 20.

The Commission should enter an Order similar to its final orders in the last round of electric cases, ICC Dockets No. 07-0539 and 07-540, that establish a natural gas SAG for stakeholders to engage with one another on issues relating to the utilities' energy efficiency programs. We agree with CUB witness Thomas that the gas SAG could be structured to facilitate coordination with the electric SAG already in existence:

> [S]ince there are joint program delivery mechanisms between electric and gas utilities, there should be a joint stakeholder mechanism as well. Ideally, the natural gas SAG would coordinate with the electric SAG already in existence when necessary. For example, the natural gas SAG could meet in the morning and the electric SAG in the afternoon, or vice versa. This would allow electric and natural gas utilities to facilitate collaboration when appropriate and necessary. Holding both an electric and natural gas SAG on the same day would be efficient for all participants and would allow them to use their time and resources efficiently.

CUB Ex. 1.0, 28.

4. The Commission Should Require the Utilities to Participate With Stakeholders to Develop a Statewide Technical Resource Manual (TRM)

Witnesses Crandall and Mosenthal both express concern about the quality of inputs and assumptions in the NS-PGL plan. *See* AG Ex. 1.0, 25; ELPC Ex. 1.0, 18-19. Mr. Crandall observes that there has been a "lack of continuity regarding input assumptions, savings estimates and net-to-gross factors" for EE programs implemented in Illinois, ELPC Ex. 1.0, 18, and in his testimony identifies "numerous inconsistencies" between the Nicor and NS-PGL filings. For example:

- Multi-family direct install showerheads - Nicor estimates 27 therms per year savings. NSG/PGL estimates 20 therms/yr savings.

- Regarding multi-family direct install and residential pipe insulation Nicor estimates savings of 34 therms/year and a 7 year useful life (for multi-family residential). NSG/PGL estimates 12 therms per year and 20 year useful life.

- For C&I boiler tune-ups Nicor estimates an annual savings of 303 therms. NSG/PGL estimates and annual savings of 242 therms/yr

ELPC Ex. 1.0, 19. Moreover, Mr. Crandall testifies there is a “high likelihood” he would have found additional inconsistencies in the Utilities’ plans and portfolios if he had more time to review the record. *Id.*

Witnesses Crandall and Mosenthal both submit that the Commission and all parties would have much greater confidence in the inputs and assumptions used in the development of EE Plans in Illinois if the Commission directs the Utilities and the other gas and electric utilities to coordinate with DCEO and SAG participants to develop a statewide technical resource manual. *See* ELPC Ex. 1.0, 20; AG Ex. 1.0, 26. As described by Mr. Crandall:

> The TRM would include a wide array of information on the details of natural gas and electric energy efficiency and demand response measures and programs. This typically includes: cost of measures, cost of installation, savings estimates in terms of estimated therms, kWh, KWs. In addition the TRM would include measures costs, useful life estimates for program measures, estimated realization rates, net-to-gross, “deemed” savings estimates for planning purposes and similar information. The energy efficiency program developers, implementers and evaluation contractors would use the TRM values for developing and modifying programs as well as the initial process or impact analyses to be done throughout the state.

ELPC Ex. 1.0,at 20.

In its Final Order in the Ameren case (No. 10-0568) the Commission directed Ameren to “work with other utilities subject to the requirements of Section 8-103 and 8-104 of the PUA and the SAG to develop a statewide TRM in the future.” Ameren Order at 70. In a somewhat confusing and contradictory passage, however, the Final Order also states that “it is neither necessary nor appropriate to order a statewide TRM in this proceeding.” *Id.* at 69-70. It is our understanding that the Commission at its December 21, 2010 Bench Session changed the Proposed Order to unambiguously direct Ameren to participate in the development of a statewide TRM through the SAG process. The Motion for Clarification filed by the Attorney General, ELPC and NRDC addresses this issue as well and requests modifications to the Final Order in order to “clarify the stated intention of the Commission” with respect to a statewide TRM. Regardless of the inconsistencies in the Ameren Order, the facts in this proceeding and the lack of continuity between Nicor and Peoples/North Shore assumptions support the need for development of a statewide TRM.

E. Commission Analysis and Conclusions

The Commission believes that Staff’s proposals are reasonable measures to support the independence of the evaluator. Language should be included in the contracts of the independent evaluation such that the Commission can: (1) terminate the contracts if it determined the evaluators were not acting independently; and (2) prevent the utilities from terminating the contracts without Commission approval.

However, the Utilities' concerns are valid. It is not our intent to terminate a contract without an opportunity for the Utilities and interested parties to be heard. Likewise, it is not our intent for the requested contract language to be a barrier to terminating contracts for reasons unrelated to the evaluator's independence. Accordingly, the Commission adopts Staff's recommendations with the qualification that the Utilities have the latitude to craft contract language that addresses the concerns we have acknowledged.

The Commission agrees that the statutory cap on the evaluation budget necessarily affects and limits EM&V activity. The Commission finds that the Utilities' proposal is reasonable and is sufficient to provide the information needed to inform the next three-year planning period.

In response to Dr. Brightwell's request, the Commission finds that it is reasonable to interpret Section 5/8-104(f)(8) of the Act to mean that the available budget to pay evaluators is limited to 3% of the total portfolio budget.

The Commission also orders the Utilities to permit its independent evaluators to determine the timing of evaluations. Consistent with our Order in Docket 10-0562, the Commission suggests that the Company provide contract language that requires at least one impact evaluation of all programs to be completed no later than 60 days prior to the date that the Company is required to file its second triennial plan.

The Commission directs the Utilities to review and verify their avoided cost calculations and provide documentation to stakeholders to allow them to meaningfully assess the Utilities' approach

We also direct the Utilities to collaborate with the natural gas SAG and evaluation contractors to develop a EM&V planning process that makes the most of the limited funds available by combining evaluation efforts wherever possible and appropriate across any combinations of gas and electric utility jurisdictions where programs are similar or jointly offered. The SAG's responsibilities should include establishing agreed-upon performance metrics for measuring portfolio and program performance. We also recommend the independent evaluator assigned to the Utilities work with the natural gas SAG to develop Experimental Design guidelines and ensure transparent and consistent methods for determining electricity and natural gas savings. The evaluator should maintain a master database of participation, billing, and control group data in order to ensure savings are verified in an independent and timely manner. The costs involved with exporting the appropriate data to the independent evaluator must be controlled by the Utilities so that the costs do not exceed the 3% EM&V threshold as required in Section 8-104 of the PUA. The Utilities should provide information on the Experimental Design methodology to its evaluator for the Company's behavior change pilot program and other programs, as appropriate.

In the Ameren Illinois Utilities' ("Ameren") gas and electric efficiency plan docket (10-0568) and Commonwealth Edison Company ("ComEd") electric energy efficiency docket (10-0570), the Commission ordered the Companies to adopt the NTG framework, as proposed by AG witness Mosenthal in his Direct testimony in this docket. It is critical that both gas and electric utilities are required to play by the same rules and assumptions. Therefore, we also direct the Utilities here to adopt the AG-proposed NTG framework.

Also consistent with our rulings in other recent dockets, the Commission agrees that the development of a TRM will be valuable. We direct the Utilities to coordinate with other utilities, DCEO and SAG participants to develop a statewide manual.

VI. PROGRAM ISSUES

A. North Shore/Peoples Gas' Position

1. Portfolio Flexibility

Mr. Mosenthal testifies about constraints on program changes during the Plan Period. AG Ex 1.0 at 48-49. As the Utilities explain in their Petition, it is impossible to anticipate every factor that may affect implementation of the Plan. For example, discussions with trade allies will likely affect program implementation. As the Utilities prepare to implement the measures and as implementation progresses, they state that they will refine the programs. They do not anticipate substantial changes to any programs, but, should any substantial changes be required, Mr. Marks states that the Utilities would file for review and approval. Mr. Marks states that Commission-imposed restrictions on flexibility, as discussed by Mr. Mosenthal, are more likely to reduce achieved savings than to maintain or increase net savings and prevent ongoing provision of programs across rate classes. The Utilities confirm they will participate in a gas utility SAG process. This will provide a forum for all parties to adequately understand any proposed changes to the Plan. The Utilities also agree that they would file substantial Plan changes with the Commission. NS-PGL Ex. 3.0 at 18.

2. Stakeholder Advisory Group

The Utilities state that, contrary to Mr. Mosenthal's speculation ("… my only conclusion is that the Utilities are resistant to effective good faith engagement with the SAG" (AG Ex. 1.0 at 46)), the Utilities can support a SAG. In fact, their Plan includes the following: "Going forward, the Utilities and stakeholders discussed forming a Stakeholders Advisory Group ("SAG") similar to the group that currently exists for the Illinois electric utilities. The Utilities could support the formation of an Illinois natural gas SAG and would fully participate in this group but urge potential participants to carefully define the group's scope." NS-PGL Ex. 1.2 at 22.

Mr. Marks states that the Utilities expect that a gas utility SAG would include members with a variety of interests. This would include consumer advocates, environmental advocates, community leaders, third party program administrators, program implementers, and other entities interested in the energy efficiency marketplace. Staff participates in the electric utility SAG meetings, and the Utilities expect that Staff would participate in any gas utility SAG. The Utilities would appreciate and value the information gained from the dialogue fostered by this group. However, Mr. Marks states that extending decision-making authority to this group, for any aspect of the Plan, is not appropriate and has the potential of impeding timely implementation of the programs and related evaluations. NS-PGL Ex. 3.0 at 19.

The Utilities state that Section 8-104 places the responsibility to meet savings goals on the Utilities and DCEO, and it also makes the Utilities liable if they do not meet their goals (subject to certain exceptions described above). Allowing a SAG, which has no statutory responsibility or liability, to preempt the Utilities' decisions about their programs is untenable. Assuming a gas utility SAG is created, the Commission should reject any decision-making role for a SAG.

In addition to the SAG, the Utilities support the formation of what they call a "gas evaluation working group." Mr. Marks states that this working group's mission would be to formulate common evaluation methodologies for each basic program type that all the utilities would use. Like the SAG, participation would be voluntary. Mr. Marks states that the working group would try and form consensus around impact evaluation methodology for like programs and then instruct its own independent evaluation contractors to implement those methodologies. This would provide consistency between utilities for like programs. Mr. Marks explains that it would differ from the SAG because evaluation issues require different skill sets. Also, the SAG would have limited time to cover many diverse issues related to planning and implementation. By breaking evaluation out into a separate group, more focus can be paid to this critical topic. NS-PGL Ex. 3.0 at 21.

3. Administrative and Marketing Costs

The Utilities' Plan specifies their program management, implementation and marketing costs. NS-PGL Ex. 1.2 at 10 (Tables 4B and 4D). The Implementation section of the Plan describes implementation plans, including administration and marketing in detail. NS-PGL Ex. 1.2 at 25-36. Communications and Marketing is included in that section. NS-PGL Ex. 1.2 at 31-34.

4. Program Recommendations

CUB-City witness Mr. Thomas states that he was "…concerned that not enough funding is spent on commercial and industrial programs." CUB-City Ex. 1.0 at 6. The Utilities respond that their initial program funding was established based on the proportion of residential *vs*. C&I revenue, and this was one of two overriding objectives underlying the Plan. Mr. Marks states that the Utilities expect that this will shift over time as the ability to achieve higher goals will become more dependent on the C&I market. NS-PGL Ex. 3.0 at 18. For this first Plan Period, the Utilities state that this split is reasonable and should be approved.

Regarding the Residential Home Energy Reports Program, Mr. Thomas recommended that "[t]he Company should include stakeholders in the RFP [request for proposal] development process, … ." CUB-City Ex. 1.0 at 11. He also provided many suggestions on what the program design should include. CUB-City Ex. 1.0 at 10-14. The Utilities disagree with these proposals. Mr. Marks states that the Utilities do not intend to include stakeholders in RFP development, as some stakeholders may wish to bid or partner on a particular RFP, and the Utilities do not want to create any potential conflicts. However, he states that the Utilities intend to issue an RFP that will allow for a wide diversity in responses and program design concepts. It is premature to develop program design details, especially since the Home Energy Reports Program is not going to be launched until the middle of 2012. Mr. Marks states that the Utilities view this as an evolving product and expect innovations to occur between now and when they plan to launch the program, and one feature the Utilities will be seeking in any proposal is a proven track record of savings. NS-PGL Ex. 3.0 at 26.

5. Total Resource Cost Test

The TRC result for the total portfolio, not including any savings or costs from DCEO, is 2.0 for North Shore Gas and 2.2 for Peoples Gas (meaning that benefits are 2.0 and 2.2 times greater than program costs, respectively). In addition, all measures and all programs in the portfolio have TRCs above 1.0, indicating that benefits are always greater than costs. NS-PGL Ex. 1.0 at 13; NS-PGL Ex. 1.2 at 9.

Dr. Brightwell recommends that the Commission limit measures to those that are cost-effective under the TRC test. ICC Staff Ex. 1.0 at 2-5. The Utilities included only measures that met the TRC test. However, the Utilities disagree that Section 8-104 requires that the portfolio include only measures with a TRC in excess of 1.0. Section 8-104(b) states in part:

> For purposes of this Section, “energy efficiency” means measures that reduce the amount of energy required to achieve a given end use and "cost-effective" means that the measures satisfy the total resource cost test which, for purposes of this Section, means a standard that is met if, for an investment in energy efficiency, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the measures to the net present value of the total costs as calculated over the lifetime of the measures. The total resource cost test compares the sum of avoided natural gas utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided electric utility costs, to the sum of all incremental costs of end use measures (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side measure, to quantify the net savings obtained by substituting demand-side measures for supply resources.

220 ILCS 5/8-104(b). The Utilities interpret this subsection as requiring the “measures” considered together as a portfolio to meet the TRC. For example, the law speaks to the “total benefits of the measures” and the sum of avoided costs relative to the sum of incremental costs of end use measures.

B. Staff’s Position

Staff recommends that only measures that are cost-effective be included in any programs or the portfolio. Dr. Brightwell explains that using a measure level Total Resource Cost (“TRC”) test allows for an analysis of whether any particular measure has greater expected value to society than it costs. (Staff Ex. 1.0, p. 3) If a particular measure is not cost-effective under the TRC, then it does not have sufficient value to society to make it worthwhile to incent. Every unit sold of a measure that is not cost effective serves to reduce the net benefit of the program.

To illustrate this point, Dr. Brightwell provides an example that supposes a portfolio consists of two measures called widgets and gadgets. The widgets have incremental benefits and costs of $1300 and $1000, respectively. The gadgets have incremental benefits and costs of $950 and $1000, respectively. The respective TRCs for widgets and gadgets are 1.3 and 0.95. Every widget that is sold adds $300 of net benefits to the program and every gadget that is sold subtracts $50 from the net benefits.

If a program incents 100 widgets and 100 gadgets, then the portfolio level TRC is 1.125. The benefits are $225,000 ($1300/widget X 100 widgets and $950/gadget X 100 gadgets). The costs are $200,000 ($1000/widget X 100 widget and $1000/gadget X 100 gadgets). It appears that this is a good portfolio because the TRC is greater than 1 and the net benefits are $25,000. However, the net benefits would have been $30,000 if the portfolio did not include rebates for gadgets ($300/widget X 100 widgets). By including gadgets in the portfolio, this Energy Efficiency Plan ("EEP") reduced the net benefits to society by $5,000 from what they would have been without the measure. (*Id*. 1.0, pp. 3-4)

Dr. Brightwell further explains that including only measures that are cost-effective removes some of the risks that the overall portfolio will be cost-ineffective. The risk associated with portfolio-level uncertainty comes from the fact that it is unknown how well customers will respond to incentives for any particular measure. If there is a high uptake of measures that are not cost-effective, the entire portfolio may be cost-ineffective as a result. (*Id.*, pp. 4-5)

C. AG's Position

1. The Role of the Stakeholder Advisory Group

The Stakeholder Advisory Group ("SAG") was first established by the Commission in ICC Docket Nos. 07-0539 and 07-0540, Ameren and ComEd's petitions for approval of electric energy efficiency plans. The SAG consists of various stakeholders, including Commonwealth Edison Company and the Ameren Illinois Utilities, who have met since 2008 to work with the utilities to reach consensus on issues such as program design and evaluation metrics. In its Orders in ICC Docket Nos. 07-0539 and 07-0540, the Commission stated:

> All parties involved, with the possible exception of Staff, maintain that a Stakeholder Advisory Committee is essential to the success of the Plan. This Commission agrees with ComEd that it should establish a stakeholder process to review ComEd's progress towards achieving the required energy efficiency and demand response goals and to continue strengthening the portfolio. The Stakeholder group's responsibilities

> include, but are not limited to: reviewing final program designs; establishing agreed-upon performance metrics for measuring portfolio and program performance; reviewing Plan progress against metrics and against statutory goals; reviewing program additions or discontinuations; reviewing new proposed programs for the next program cycle; and reviewing program budget shifts between programs where the change is more than 20%.

ICC Docket No. 07-0539, Order at 24; ICC Docket No. 07-0540, Order at 32.

The People believe that utility collaboration with the existing Stakeholder Advisory Group is critical to ensuring the establishment of cost-effective energy efficiency savings programs. The key role the SAG can and has played in developing energy efficiency programs in Illinois has been documented in all of the energy efficiency dockets initiated in 2010. The collaboration needed to establish gross savings values and NTG values is discussed above in Section III of this Brief.

It is worth noting that the Utilities' commitment to SAG collaboration seems to be lacking. It clearly opposes any collaboration on the establishment of the key gross savings and NTG variables that are integral to the calculation of verifiable energy savings. NS-PGL Ex. 3.0 at 19. Mr. Mosenthal testified that in response to a number of AG data requests (AG 2.12, 2.15 & 2.16), the Utilities were asked a series of questions about their willingness to engage with the SAG on various issues. The Utilities declined to directly answer the questions. Rather, they simply indicated that "No [SAG] presently exists for gas programs, and that the [the Utilities did] not know what form such a SAG may take and what role it may play." AG Ex. 1.0 at 45-46. While the Utilities state that it would "value the information gained from the dialogue fostered by this group", they aver that "extending decision-making authority to this group, for any aspect of the Plan, is not appropriate and has the potential o impeding timely implementation of the programs and evaluations." NS-PGL Ex. 3.0 at 19. The People could not disagree more. As noted above, and as documented in the electric utility dockets, the SAG collaboration on the electric side has benefited all stakeholders. While the responsibility to achieve the savings and deliver the programs rests with the utility under Section 8-104, ratepayers are providing through a separate rider 100% of the funding these programs, which are specifically designed to reduce both the direct and indirect costs of utility service. 220 ILCS 5/8-104(a). As such, ratepayers have a compelling interest and stake in ensuring program dollars are spent prudently and cost-effectively. In that regard, the creation of the SAG on the electric side was a recognition of this special interest. The ICC should therefore order this collaboration, as it has for the electric utilities in their first three-year plan.

2. Portfolio Flexibility

The Utilities have proposed that it be afforded virtually unlimited flexibility to shift budgets between programs, to add or drop measures, and to modify incentives without ICC approval.[95] ComEd, in its Plan in Docket 10-0570, proposed similar flexibility, but it

[95] NS-PGL Ex. 1.2 at 41.

also established criteria by which it would inform the SAG if it intended to significantly modify the plans (similar to the guidance required by the ICC in its prior Order). In its current electric efficiency plan docket, ComEd proposed and the Commission adopted a plan to fully discuss with the SAG prior to initiating the change, any shift in the budget that results in a 20% or greater change to any program's budget, or that eliminates or adds a program.[96] Presumably, these modifications would then be discussed and debated among the SAG, and while the utility would ultimately have responsibility for any decisions, SAG members would be free to petition the ICC for reconsideration if they were not able to come to a satisfactory agreement.

The Utilities have not specifically proposed conditions on their proposal for program flexibility similar to ComEd. As the entities with responsibility for meeting goals and potentially at risk for penalties, the People support allowing the Utilities some flexibility to manage their portfolios and make midcourse corrections as appropriate, as it learns more from evaluations, market conditions, and actual experience with program penetrations, subject to the same conditions as ComEd has proposed. That being said, there is a tension between this flexibility and issues surrounding the deeming of impact values. If all values are deemed for the full three-year plan period, then the Utilities may have perverse incentives to modify the portfolios in ways that are not conducive to optimizing true net savings, but rather optimizing their savings claims based on deemed values that may no longer be appropriate. Clearly the option of adding and deleting measures and modifying incentives can have significant impacts on NTG ratios. AG Ex. 1.0 at 48.

As discussed above, the People oppose the Utilities' deeming proposal. However, if the ICC were to approve the Utilities' proposal to deem most measure impact factors for a full three-year period, flexibility should be much more limited. Essentially, any deemed value should be dependent on specific program design details. With complete flexibility, the Utilities would be free to modify programs in ways that result in program designs and strategies that no longer reflect those for which NTG values were initially deemed. Accordingly, the People support the flexibility the Utilities have requested, but only if the ICC adopts Mr. Mosenthal's proposal for establishing gross savings and NTG values. Mr. Mosenthal also recommended that the Commission adopt additional restrictions on the Utilities' flexibility proposal in addition to ComEd's list of criteria that would trigger SAG involvement. These additional limitations are:

1. The Utilities shall not shift more than 10% of spending between residential and C&I sectors without ICC approval; and

2. The Utilities shall not modify their plans such that they no longer meet the statutory requirements for allocations to the low income and state and local government markets.

Id. at 49.

Mr. Mosenthal testified that these criteria are appropriate for reasons of equity. First, unlimited shifting between sectors should be clearly tied to the

[96] ComEd Ex. 2.0 at 61 – 62.

reconciliation of any riders to guard against cross subsidies between these sectors. While opportunities to ensure that each sector only contributes to programs available to it can be dealt with at the time specific program cost recovery riders are established or reconciled, a relative balance of services and benefits to residential and C&I customers is also a compelling interest that justifies formal pronouncement of criteria by the Commission.

The second criterion ensures equity for low-income and government customers for which the General Assembly indicated a clear intent to allocate at least a minimum portion of the overall portfolio expenditures. 220 ILCS 5/8-104(f)(4). *Id.*

3. Joint Delivery of Programs with ComEd

The Utilities' plan to jointly offer certain programs with ComEd while others will be implemented in coordination with ComEd. NS-PGL Ex. 1.2 at 5, 26, 44. Offering joint programs is an appropriate use of ratepayer funds and can help leverage savings across multiple utility services, reduce administrative costs, and provide a higher level of customer service by addressing all their energy needs in a one-stop-shopping fashion. AG Ex. 1.0 at 50. Similarly, coordinated programs, where applicable, also can result in similar positive benefits. But, such joint and cooperative efforts need to be choreographed from the beginning, and each utility needs to clearly understand their respective roles. The Utilities' plan, however, appears to lack specificity in many respects.

For example, for some programs, the Utilities claim it will "look for joint measures that can benefit both gas and electric use."[97] In other instances, the Utilities say it will "coordinate their efforts with ComEd when possible."[98] For still other programs, the Utilities claims it "intends" to offer the program "jointly" with ComEd.[99] Despite these assertions, however, Mr. Mosenthal testified that the Utilities' responses to AG data requests revealed that they have put little to no planning into the actual implementation of these joint and coordinated programs. NS-PGL's response to AG 2.01(i) states that: "North Shore and Peoples Gas made no assumptions regarding estimated participants for Commonwealth Edison Company (ComEd) customers."[100] To deliver a joint program — for example the small business direct install program — it is essential that all cost-effective gas and electric measures be available to all participants at the time of service. Therefore, program plans, budgets and goals need to be based on a consistent number of expected participants. The Utilities' responses to AG 2.01 and 2.02 makes clear this essential planning has not yet been done. AG Ex. 1.0 at 50.

Moreover, if the Utilities were to increase its investment up to the revised spending cap -- meaning budgets and savings goals incorporate all appropriate transportation load and allocate additional funds to joint and cooperatively offered programs -- both electric and gas savings could increase substantially. Currently,

[97] NS-PGL Ex. 1.0 at 9
[98] NS-PGL Ex. 1.0 at 9
[99] NS-PGL Ex. 1.0 at 9
[100] AG Ex. 1.0 at 50.

ComEd has indicated these programs are "smaller in scope than we would have wanted".[101]

Based on the Utilities' plans, the specific commitments and details of joint and coordinated efforts are not clearly provided. The Commission should direct the Utilities to revise their plans to commit to these integrated electric-gas program efforts, and ensure their plans correctly match ComEd's plans to efficiently and effectively pursue integrated programs.

More precise information about coordination is needed for other jointly offered programs as well. For example, the Utilities state that they intend to offer business custom programs in coordination with ComEd, when possible. The Utilities and ComEd will also collaborate in raising awareness of and educating customers on the benefits of energy efficiency.[102] But, the Utilities do not offer any specificity as to how it will coordinate or collaborate with ComEd to address their customers' electric and gas savings needs. Peoples Gas and North Shore claim that no assumptions, for example, have been made with respect to the allocation of program costs or participants.[103] Such a lack of specificity and effort in planning will undermine the effectiveness of the custom program and will result in lost energy efficiency opportunities. Despite the Utilities' response that they have not estimated participants, they do provide participation figures and costs in NS-PGL Ex. 1.2, and as shown in the table below. As the table demonstrates, the Utilities' estimated participation rates and spending are symptomatic of its lack of effort:

Business Custom	PY 1	PY2	PY3	Cumulative
Peoples Gas	30	70	100	200
North Shore Gas	6	13	19	38
Total Participants	**36**	**83**	**119**	**238**
Total Combined Custom Budget	**$314,549**	**$595,863**	**$773,981**	**$1,684,393**
ComEd Business Custom Participants	**400**	**500**	**600**	**1500**
ComEd Business Custom Budget	**$6,105,332**	**$5,367,038**	**$6,758,643**	**$18,231,013**

AG Ex. 1.0 at 52.

ComEd expects to reach 1,500 custom customers in its service areas, but the Utilities expect only 238 (between Peoples and North Shore) of its customers to install custom gas measures. Similarly, ComEd expects to invest more than nine times the amount that the Utilities expect to invest in business custom projects. While clearly some of ComEd's customers are also customers of Nicor rather than Peoples Gas' and North Shore's, it appears from the table above that the level of activity PGL/NS is planning would result in many of the custom program participants not actually receiving any gas measures, given the very high penetration of gas usage in ComEd's territory.

[101] ComEd Ex. 2.0 at 22 (Brandt); ICC Docket No. 10-0570.
[102] NS-PGL Ex 1.2 at 74.
[103] *See,* AG Ex. 1.0 at 52.

Mr. Mosenthal testified that he would expect the number of participants and levels of spending to more consistent between ComEd and the Utilities. AG Ex. 1.0 at 51-52.

Jointly providing custom programs with ComEd, and aggressively ramping up gas energy savings projects will improve program impacts and customer service. It will also increase the average proportional share of gas savings per custom project. While it is not essential to have a single implementation contractor deliver custom services, it is critical for each utility to assess energy savings opportunities holistically. This means that irrespective of how customers are enrolled into a custom program, the implementers need to perform a whole-building assessment and pursue all cost-effective opportunities within each customer facility. Thus, if a customer is engaged initially through the Utilities, it should be their responsibility to manage the project, provide customers with a single point of contact, ensure ComEd's implementation staff are apprised of the electric savings opportunities and vice versa, while providing service to a customer that leverages both gas and electric utilities' offerings. Under the current proposed program design, many energy savings opportunities would be lost because neither the gas nor the electric implementation contractors are expected to fully integrate their services, other than build to customer awareness. *Id.* at 52.

In sum, the Utilities have not provided enough detail to fully understand their cooperatively and jointly provided programs to ensure the effective integration of programs. Not only do many of the figures the Utilities and ComEd provide seem illogical given supposed joint or cooperative programs, but it seems clear that the commitment to truly integrate efforts has not been made, or at least not been detailed in the planning process. The Commission should reject the Utilities' plan for the many reasons discussed above, and also direct the Utilities and ComEd to work together to effectively design a single set of integrated programs that truly will be delivered in a seamless fashion to all eligible customers, thereby providing for the implementation of all cost-effective comprehensive gas and electric measures.

4. The Utilities' Contract with Franklin Energy Services

As noted in the introduction of this Brief, the Utilities have no in-house experience delivering energy efficiency programs, and have contracted with Franklin Energy Services to be their "turnkey" provider of efficiency services. NS-PGL Ex. 1.2 at 26. As such, Franklin and its sub-contractor AEG were hired by the Utilities both as its implementer and its planner, and are the chief architects of the Plan. Mr. Mosenthal testified that this dual role is somewhat problematic because it can result in a possible conflict of interest. Essentially, Franklin has an incentive to develop program plans that can help reduce its implementation risk and maximize their profits rather than be focused on long-term societal benefits. Franklin, or its subcontractor AEG, have also developed the assumptions and values the Utilities are now asking the Commission to deem, essentially establishing their own performance metrics as well.

As noted by AG witness Mosenthal, it is somewhat problematic and not in the best interests of ensuring the achievement of cost-effective EE programs when perceptions of conflict can occur. Given that the performance metrics have been developed by the implementers themselves, who seek a performance-based contract, this adds additional imperative that the ICC reject deeming and ensure that the best available, independent estimates of actual savings are relied upon for purposes of measuring energy savings.

It is therefore imperative that an open bidding process be a part of any program offered by the utilities. Specifically, it should not be presumed that Franklin (or any other entity) shall be the implementation contractor for the discrete residential and commercial programs. The People are aware that there are many local entities in the Chicago area, the Utilities' service territory, that provide efficiency services. Given that these programs are funded with ratepayer dollars, the Commission should order the Utilities to engage in an open and fair bidding process, developed in collaboration with the SAG, that provides local entities an opportunity to participate in program delivery. Millions of ratepayer dollars are at stake in the delivery of the Section 8-104 energy efficiency programs. A transparent, open bidding process will help ensure that those ratepayer dollars are well spent.

D. CUB-City's Position

1. Role of the Stakeholder Advisory Group

The Commission approved an electric SAG in its final order in Ameren and ComEd's 2007 energy efficiency dockets.[104] CUB and other stakeholders who are also intervenors in this docket have participated in the SAG, including the AG, the Natural Resources Defense Council ("NRDC"), and ELPC. Other utilities have found the SAG process beneficial – both Ameren and ComEd expressed support for the SAG based on the value they feel it brings to their Plans "as an excellent opportunity and forum for a variety of stakeholders to work together to ensure energy efficiency is maximized in Illinois."[105]

Both Peoples Gas and North Shore recognize the importance of obtaining agreement among stakeholders. Utilities' witness Mr. Marks explained the utilities' commitment to working with stakeholders, including the issues of implementation, evaluation, tracking and cost recovery.[106] While developing their Plan, the Utilities met with Commission Staff, the Illinois Attorney General's Office, CUB, the City, and ELPC.[107] The Utilities support the formation of a natural gas SAG and have stated that they would fully participate in this group..[108] The Utilities agree that the natural gas SAG should meet on the same day each month as the electric SAG to facilitate coordination between the two groups.[109]

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[104] See ICC Docket No. 07-0539; ICC Docket No. 07-0540.

[105] ComEd Ex. 2.0 at 60, ICC Docket No. 10-0570.

[106] NS-PGL Ex. 1.0 at 8.

[107] *Id.*

[108] NS-PGL Ex. 1.2 at 22.

[109] Transcript at 54.

All intervenors who address the SAG in testimony believe the electric SAG process has been valuable and recommend the Commission direct the Utilities to participate in a natural gas SAG. AG witness Mosenthal believes that the SAG process has "worked well" and is valuable.[110] ELPC witness Crandall recommends that the Utilities participate in a natural gas SAG, referring to the SAG as "constructive and useful."[111] CUB/City witness Mr. Thomas supports the SAG as an excellent arena for utilities and stakeholders to engage with one another on issues relating to the utilities' energy efficiency programs, noting that the Utilities' Plan reflects how important they find the SAG process.[112]

CUB/City prefer that the SAG be kept advisory. In ICC Docket No. 10-0562, Nicor Gas witness James Jerozal proposes specific guidelines for a natural gas SAG in rebuttal testimony, including:

> (1) Advisory – Nicor believes the group should be advisory in nature and focused on assisting the Company to consider a broad range of perspectives to improve the overall EEP and its operations.
>
> (2) Broad-based – A well designed advisory group would represent a broad base of interests including consumer advocates, environmental advocates, community leaders, program implementers, union leaders, trade groups, manufacturers, distributers, contractors, ESCOs, businesses, the public and other entities interested in the energy efficiency marketplace. ICC Staff should be a participant or observer.
>
> (3) Structure – The governance process, meeting schedule, objectives and roles for the participants should be well-defined but not overly complex.[113]

CUB and the City encourage the Commission to adopt these guidelines as proposed by Nicor Gas. The General Assembly intended that utilities be responsible for meeting statutory goals, which is made clear by including penalties in Section 8-104 of the PUA. Giving the SAG a formal role in managing Peoples Gas and North Shore energy efficiency programs, and those of other electric and natural gas utilities, goes against this intent. In ICC Docket No. 10-0568, Ameren witness Mr. Martin summarized the role of the SAG effectively by noting that the SAG includes a variety of interests, making the extension of decision-making authority to this group inappropriate with the potential to impede timely implementation of utility programs and related evaluations.[114]

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[110] AG Ex. 1.0 at 48, footnote 58.

[111] ELPC Ex. 1.0 at 18.

[112] CUB/City Ex. 1.0 at 24-25.

[113] Nicor Ex. 5.0 at 8, ICC Docket No. 10-0562.

[114] Ameren Ex. 6.0 at 22, ICC Docket No. 10-0568.

CUB and the City recommend that the Commission create a separate SAG for the natural gas utilities subject to Section 8-104 of the PUA, and that the electric SAG and natural gas SAG be directed to coordinate their meetings. Ameren, a utility that has integrated gas and electric Plan, supports a joint SAG process.[115] CUB/City envision an electric SAG meeting for a half day, and a gas SAG meeting the other half, to allow for communication and collaboration when appropriate and necessary.[116] The Utilities agree with this approach.[117] The Commission should direct Peoples Gas and North Shore, as well as the other utilities, to participate in a natural gas SAG.

2. Behavior Change

The Utilities propose a behavior change program for residential customers, Residential Home Energy Reports, in Plan years 2 and 3.[118] This program targets single family homes in "high-impact savings segments," meaning customers with high natural gas usage. The Utilities plan to target customers in all socio-economic levels in their respective service areas.[119] The Utilities will provide reports to participants in this program four to five times during a heating season. Report information to participants will include "consistent feedback on their energy use, comparisons to similar homes in their neighborhood, and targeted tips to achieve energy savings."[120]

The Peoples Gas Residential Home Energy Reports program will reach 30,000 customers in year 2 of the Plan (the first year of the program), projecting to save 76,280 therms with a budget of $439,240. In year 3, the program will reach 60,000 customers and is projected to save 952,560 therms with a budget of $574,248.[121] The North Shore Residential Home Energy Reports program will reach 5,000 customers in its first year and is projected to save 79,380 therms with a budget of $77,513. In the second year of the program, (Plan Year 3), the program will reach 10,000 customers and is projected to save 158,760 therms with a budget of $101,338.[122] CUB/City commend the Utilities' innovative plan to offer a behavior change program to residential customers. It is an important tool to determine cost-effective strategies for future plans.

CUB/City propose only a few additional recommendations the Commission can adopt to ensure the Utilities behavior change programs provide a useful foundation for the Utilities use in future Plans:

[115] Ameren Ex. 6.0 at 24, ICC Docket No. 10-0568.

[116] CUB Ex. 1.0 at 13.

[117] Transcript at 54.

[118] NS – PGL Ex. 1.2 at 51.

[119] NS – PGL Ex. 1.2 at 51.

[120] NS – PGL Ex. 1.2 at 51.

[121] NS-PGL Ex. 1.2 at 54.

[122] *Id.*

- The Utilities should use an open bidding process for this program to ensure that the Utilities are able to offer the most cost-effective behavior energy savings program available.
- The Utilities should increase their behavior change program to include an RFP from third-parties.
- The Utilities' RFP should be explicit in how the vendor selection process will work, including whether the Utilities will select a provider that demonstrates it will cost-effectively efficiently administer this type of behavior change program.[123]
- The Utilities should collaborate with ComEd in offering this program.

CUB/City believe it is important for the Utilities to collaborate with ComEd on their behavior change programs. The Utilities have stated their plan to offer a joint behavior change program with ComEd, but did not provide detailed information about that collaboration.[124] CUB/City believe a joint program with ComEd could potentially be a more cost-effective way to reach customers shared by the two utilities, as well as an opportunity to reach hard to reach customer segments.[125]

The Utilities' Residential Home Energy Reports programs are cost-effective; Peoples Gas's program has a TRC of 1.07 and North Shore's a TRC of 1.09.[126] The Utilities could cost-effectively find greater savings by allocating funding towards increasing the behavioral energy savings pilot by issuing an RFP for a third-party administered program.[127]

All of CUB/City's recommendations here are consistent with the Commission's Order in ICC Docket No. 10-0568, where the Commission noted support of behavior change programs, agreeing that Ameren should bid out a program by including an RFP process, requiring the independent contractor selected by the utility to apply the California Experimental Design methodology, and increase participation levels.[128] Applying those changes to the Utilities' programs will not only ensure that the Utilities' behavior change programs are used as cost-effectively as possible, but if adopted they will ensure that behavior change programs can be used to build a foundation based on actual savings realized by customers which can be used to meet the increasingly aggressive statutory savings goals required by Section 8-104 of the PUA.

[123] CUB Ex. 1.0 at 10.

[124] NS-PGL Ex. 1.2 at 51-52.

[125] CUB/City Ex. 1.0 at 16-17.

[126] NS-PGL Ex. 1.2 at 54.

[127] CUB Ex. 1.0 at 12.

[128] ICC Docket 10-0568 Final Order at 87-88.

3. Administrative and Marketing Costs

a) Administrative costs should remain at approximately 5% and the Company should adopt a definition of "administrative costs."

The programs proposed by the Utilities in their Plan are entirely funded by ratepayers, therefore it is important that as much money as possible is spent on incentives that result in measurable energy savings. The Commission should adopt a consistent definition of "administrative costs" so that it can more easily monitor how much any utility is spending internally rather than on direct program administration. A consistent definition of "administrative costs" among the utilities who have filed Plans pursuant to both Sections 8-103 and 8-104 of the PUA would simplify the evaluation process and help ensure that as many ratepayer dollars as possible are spent achieving actual energy savings.

The Utilities define "administrative costs" as "[A]ny activity that does not directly touch the end use customer or trade allies needed to drive results for the program. In addition to administrative costs, the current administration budget includes time and applicable direct costs (*e.g.*, mileage) for a Franklin Energy Services, LLC senior level portfolio manager who will be responsible for overseeing the operations of the entire NSG/PGL portfolio of programs but could also become involved in the management of specific programs, such as the Multifamily Direct Install program."[129]

The Utilities further define administrative costs as costs "that may be incurred by a Program Administrator, Contractor or Subcontractor that is not easily chargeable to a specific program, but benefits all functions of the Program Administrator, Contractor or Subcontractor. Administrative costs should be charged to different programs and/or functions using a consistent pre-defined basis." The Utilities provide specific examples of such functions, including the following:

- Managerial and Clerical Labor;
- Human Resources Support and Development;
- Travel and Conference Fees;
- Overhead (General and Administrative);
- Equipment (e.g., communications, computing, copying, general office, transportation, etc.);
- Food Service;
- Office Supplies and Postage; and
- Labor (e.g., accounting, facilities management, procurement, administrative, communications, information technology, telecommunications, etc.).[130]

[129] NSG-PGL Response to AG Data Request 2.17.

[130] NSG-PGL Response to AG Data Request 2.17.

CUB/City accept the Utilities' definition

While CUB/City does not recommend that the Commission strictly cap administrative costs, such costs should be held at approximately 5% of the total portfolio and should be monitored. Doing so will help ensure that as much of ratepayers' money as possible is spent on achieving actual energy savings. The Utilities' Plan proposes to spend 4% on administrative costs.[131] CUB/City commends the Utilities efforts to keep their administrative costs low.

Compared to other utilities, the Utilities' administrative costs are the lowest in Illinois. Ameren's administrative costs come close, at approximately 5% of its total portfolio in ICC Docket No. 10-0568. [132] In comparison, Nicor's "Internal Administration" costs total 11.5% of the Company's first year budget, 8.1% of the second year, and 6.6% of the third.[133] Administrative costs, which result in no energy savings, are clearly an area that the Commission should give particular attention. Given the clear disparity between the reasonable levels of administrative costs proposed by the Utilities and other gas utilities filing energy efficiency plans, it is necessary for the Commission to monitor administrative costs.

2. The Utilities should report annually to the Commission on their marketing expenditures.

Monitoring marketing costs is important to ensure that ratepayer dollars are wisely spent, leaving more funding available to achieving energy savings. CUB/City witness Thomas explained that utilities have an incentive to market their energy efficiency programs more heavily than necessary due to the goodwill that energy efficiency programs engender to the utility brand, and therefore marketing costs should be carefully monitored to ensure that utilities are leveraging innovative cost-effective communication strategies, not just publicizing their own brands.[134]

The Utilities do not explicitly define "marketing costs" in their Plan, but make a commendable effort to provide detailed information about marketing efforts for each program, using Franklin Energy as a contractor to educate their customers and trade allies.[135] The Utilities propose to spend 4% of their entire portfolio on marketing costs.[136] This level of spending appears reasonable compared to other utilities filing an energy efficiency plan. For example, Ameren proposes to spend 2.5% of its total portfolio on marketing costs in ICC Docket No. 10-0568.[137]

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[131] NSG-PGL Response to AG Data Request 2.17.

[132] Ameren Ex. 1.1 at 46, ICC Docket No. 10-0568.

[133] CITE

[134] CUB/City Ex. 1.0 at 33.

[135] NS-PGL Ex. 1.2 at 31-32.

[136] NS-PGL Response to AG Data Request 2.17.

[137] Ameren Ex. 1.1 at 46, ICC Docket No. 10-0568. ComEd does not specifically define

Due to the importance of monitoring marketing costs, the Commission should order the Utilities to report annually on marketing costs for each of its residential and business programs, and make the report available to SAG members for review.

E. Commission Analysis and Conclusions

The Commission agrees that allowing the Utilities some flexibility to adjust their portfolios and implementation plans is important. This is especially true for the first program period. The Utilities should follow the criteria established in Docket 10-0570 The Utilities should fully discuss with the SAG prior to initiating the change, any shift in the budget that results in a 20% or greater change to any program's budget, or that eliminates or adds a program. Further, he Utilities shall not shift more than 10% of spending between residential and C&I sectors without Commission approval. The Utilities shall not modify their plans such that it no longer meets the statutory requirements for allocations to the low income and state and local government markets.

The Commission agrees with all the parties who are advocating the formation of a gas utility SAG. The Utilities shall participate in a SAG so that consumer and governmental shareholders can collaborate with the Utilities relating to their energy efficiency programs. The gas SAG should be structured to facilitate coordination with the electric SAG already in existence.

However, the Utilities are correct that this group's role should be advisory. The Utilities and DCEO are ultimately responsible for meeting the statutory goals, and it would not be fair or reasonable to allow an advisory group to tie their hands. The Commission further finds that the Utilities' proposed gas evaluation working group may be a useful addition to the SAG.

The Commission agrees with CUB-City that it is important to monitor administrative costs. Section 8-104 does not impose any specific cap on these costs, and the Commission declines to impose a cap. The Utilities shall report annually on administrative costs and marketing costs for each of its residential and business programs, and make the report available to SAG members for review

The Commission agrees with the Utilities that Section 8-104 does not require each measure to meet the TRC test, but it does require the portfolio (except for the low income portion) to meet the TRC test. The Commission declines to make the finding requested by Staff witness Brightwell.

Consistent with the Commission's Order in Docket No. 10-0568, we encourage the Utilities to collaborate with ComEd on their behavior change programs. The Utilities have stated their plan to offer a joint behavior change program with ComEd, but did not provide detailed information about that collaboration.

"marketing costs" in its Plan or explain the costs it plans to spend on marketing, citing ComEd Response to CUB Data Request 2.09.

VII. PROPOSED RIDER EOA

A. North Shore/Peoples Gas' Position

The Utilities' proposed cost recovery tariff is called Rider EOA. NS-PGL Ex. 2.1; NS-PGL Ex. 2.0 REV at 5.[138] As Staff witness Ms. Hathhorn testifies, the Utilities agreed to four specific language changes in responses to data requests. ICC Staff Ex. 4.0. Also see, Staff Recommendations to Rider EOP, *infra.*

Mr. Korenchan testifies that Rider EOA applies to all service classifications but not to exempt or self-directing customers under Section 8-104(m) of the Act. The rider will recover eligible costs of energy efficiency and on-bill financing through per customer charges. Energy efficiency costs would include the Utilities' and DCEO's costs. Mr. Korenchan testified that Rider EOA per customer charges would be determined separately for:

1) Residential Energy Efficiency for S.C. No. 1;
2) Residential Energy Efficiency for S.C. No. 2;
3) Commercial-Industrial Energy Efficiency for combined Peoples Gas' S.C. Nos. 2; 4 (Large Volume Demand Service); 5 (Contract Service for Electric Generation); 7 (Contract Service to Prevent Bypass); and 8 (Compressed Natural Gas Service and North Shore's S.C. Nos. 2; 3 (Large Volume Demand Service); 4 (Contract Service to Prevent Bypass); and 6 (Contract Service for Electric Generation);
4) On-Bill Financing for S.C. No. 1; and
5) On-Bill Financing for S.C. No. 2.

NS-PGL Ex. 2.0 REV at 6.

Mr. Korenchan explains that each per customer charge ("Effective Component") is the sum of applicable residential energy efficiency, C&I energy efficiency, and on-bill financing per customer charges. The Effective Components for each service classification closely mirror the budgets and programs available to each service classification. Mr. Korenchan explains that, following each Program Year (the twelve-month period beginning June 1), the Utilities would prepare reconciliation statements comparing recoveries through Rider EOA to actual expenses incurred during the year. Amounts over- or under-recovered plus interest are converted to per customer adjustments, which are amortized over a nine-month period commencing September 1. Any amounts over- or under-recovered from the Reconciliation Adjustments are then carried over into the next year's reconciliation. Section D of Rider EOA specifies the methodologies for calculation of the Effective Components, Reconciliation Adjustments and Commission Ordered Adjustments, and the process for revising Effective Components during the Program Year. NS-PGL Ex. 2.0 REV at 6-7.

[138] The Utilities explains that this exhibit is not in the required tariff format but includes the substance of the Utilities' proposal. When the Utilities make their compliance filings, they will conform the rider as well as any required changes to the Table of Contents to the Commission's format rules. NS-PGL Ex. 2.0 at 5.

Mr. Korenchan states that Rider EOA provides for several Commission filings:

1) Annually, the Utilities would file reports showing the determination of the Effective Component to be in effect during the upcoming Program Year. Rider EOA provides for revisions to the budget and Effective Components during the Program Year if necessary.

2) Commencing in 2012, the law provides that the Commission will initiate an annual review to reconcile any amounts billed in the previous Program Year with the actual costs. The Utilities would annually file the reconciliation and reconciliation adjustments no later than August 31.

3) Within 45 days of the end of each quarter, the Utilities would file status reports tracking implementation of and expenditures for each utility's portfolio of energy efficiency measures and DCEO's portfolio of energy efficiency measures.

4) No later than February 1, the Utilities would file an annual internal audit. The audit includes several tests to determine whether calculations and reports are in accordance with the terms in Rider EOA. NS-PGL Ex. 2.0 REV at 7-8.

Mr. Korenchan explains why a per customer rate design, as opposed to a per therm approach, is sound. The Utilities based their current rates on rate design objectives, including: (1) better align costs and revenue recovery; (2) provide equity between and within rate classes; (3) maintain rate design continuity; (4) reflect gradualism; and (5) retain customers on their systems. Rider EOA is an extension of those objectives. Mr. Korenchan elaborates on each point.

First, unlike a per therm charge, amounts billed under a per customer charge are not influenced by usage variations caused by weather and fluctuating gas prices as well as other influences that can contribute to larger over- or under-recoveries. Recoveries are relatively stable and more predictable with a per customer methodology, thus making funding to implement the Utilities' and DCEO's measures more stable.

Second, charges for each rate class reflect the costs budgeted for the programs that customers in each rate class are eligible to participate in and benefit from. Costs are spread evenly among customers within the rate class or classes.

Third, Rider EEP (funding for the Chicagoland Program) uses a per customer charge for recovery of eligible costs.

Fourth, the per customer charge contributes to gradualism through spreading costs evenly among customers rather than potentially adversely impacting larger usage customers with a per therm charge.

Fifth, retention of customers on the system benefits all customers through increased sharing of fixed costs.

NS-PGL Ex. 2.0 REV at 8-9.

Mr. Korenchan states that collections under Rider EOA determine "available funding." Available funding per Section 8-104(e) is the funding "associated with energy efficiency programs approved by the Commission." Therefore, when the tariff uses the term “available funding,” this means that DCEO is entitled (subject to meeting other legal requirements) to receive 25% of amounts recovered from customers under Rider EOA for each of the Utilities. NS-PGL Ex. 2.0 REV at 14.

Dr. Brightwell advocates a per therm mechanism, rather than a per customer mechanism. ICC Staff Ex. 1.0 at 7-10. Mr. Mosenthal opposes the Utilities’ proposed per customer mechanism. For the reasons described above, the Utilities continue to support a per customer approach. Mr. Korenchan responds by stating that, first, a per therm approach creates an uncertain revenue stream. Second, the bill impacts of a per therm approach are substantial.

First, the Utilities explain that amounts collected under the per therm method are necessarily a function of billed consumption. In months when usage is relatively low, amounts billed and collected under Rider EOA will likewise be relatively low. This could be especially problematic for DCEO, as, consistent with the law, the Utilities will forward funds to DCEO only after they are collected (“A utility shall not be required to advance any moneys to the Department but only to forward such funds as it has collected. 220 ILCS 5/8-104(e).) Mr. Korenchan states that recoveries from customers under a per customer methodology are relatively stable because customer counts do not fluctuate significantly on an annual basis. However, therm deliveries do fluctuate. In the last five calendar years (2005-2009), for example, the Utilities experienced years that ranged from about 8.5% warmer than normal to about 9.5% colder than normal. In warmer than normal years, lower therm deliveries would result in Rider EOA recovering less than required to meet the budget under a per therm methodology. NS-PGL Ex. 2.0 REV at 9; NS-PGL Ex. 4.0 at 11.

Second, Mr. Korenchan analyzed the bill impacts associated with a per therm approach. With a per customer methodology spreading costs evenly across accounts within service classifications, cost recovery is better aligned to the Utilities’ Plan, which spread initiatives across all types of customers and does not heavily target the largest customers over smaller customers. Under a per therm methodology, the majority of costs are funded by the largest customers from each service classification. In aggregate, 20% of customers (*i.e.*, larger customers) would fund 58% of the costs under a per therm methodology. NS-PGL Ex. 4.0 at 10. More specifically, Mr. Korenchan determined that:

Peoples Gas			
SC	**Per Customer (annual)**	**Per Therm (annual, range)**	**Top 20% under Per Therm**
1	Year 1: $4.92 Year 3: $8.40	Year 1: $0 - $90.72 Year 3: $0.01 - $160.90	41%
2	Year 1: $53.76 Year 3: $102.96	Year 1: $0 - $3,266.80 Year 3: $0.01 - $6,183.58	78%

4, 5, 7, 8	Year 1: $28.08 Year 3: $53.88	Year 1: $147.77 - $68,915.08 Year 3: $277.81 - $129,560.35	59%

North Shore			
SC	**Per Customer (annual)**	**Per Therm (annual, range)**	**Top 20% under Per Therm**
1	Year 1: $4.80 Year 3: $9.12	Year 1: $0 - $186.06 Year 3: $0.01 - $357.81	40%
2	Year 1: $51.96 Year 3: $106.32	Year 1: $0 - $3,094.98 Year 3: $0.01 - $6,616.86	78%
3, 4, 6	Year 1: $29.76 Year 3: $60.84	Year 1: $1,282.80 - $39,424.95 Year 3: $2,755.64 - $84,690.64	68%

NS-PGL Ex. 4.0 at 7-10; NS-PGL Ex. 4.1.

Dr. Brightwell testifies that a per therm methodology should be used to provide equity and proper price incentives to reduce usage. ICC Staff Ex. 1.0 at 7. Mr. Korenchan disagrees and states that a per customer methodology provides a fair and equitable method for recovering costs from customers and manages bill impacts across customers. In addition, Mr. Korenchan states that customers receive adequate price signals through their utility bills and the per customer methodology contributes only incrementally to provide price signals to all customers, rather than emphasizing only the largest customers, through the additional billed amount. The Utilities' Plan is intended to reach all customers, rather than overly emphasizing the largest customers who are a major focus of Dr. Brightwell's approach. The Plans are designed to provide programs to residential and C&I customers at approximately the same proportion as the revenues each sector contributes to the customer base. NS-PGL Ex. 4.0 at 10-11.

Mr. Mosenthal states (AG Ex. 1.0, p. 20) that the Utilities will charge the "largest customers (service class Nos. 4, 5, 7 and 8) *only about half as much as smaller customers* (service class No. 2). [footnote omitted] Presumably, this is based on the Utilities excluding most of the commodity costs of these very large customers in its revenue calculations. This creates a very inequitable system." Mr. Korenchan explains that Mr. Mosenthal's presumption is incorrect. While it is true that the Utilities only calculate estimated commodity costs for small volume transportation customers, estimated commodity costs are only used in the calculation of the rate cap spending limits and not as a basis for establishing budgets within those limits. Since the Utilities' proposed budgets for the first three program years result in average increases to customers' bills well below the caps, estimated commodity cost is not a factor. Mr. Korenchan states that the reason that the proposed per customer charges for S.C. No. 2 is larger is because, as a "General Service" rate, it includes both larger residential and C&I customers. The budget for S.C. No. 2 includes programs for both residential and C&I customers. Since the residential programs are not targeted towards S.C. Nos. 4, 5, 7 and 8 (Peoples Gas), it is appropriate to charge these service classifications only for their share of the C&I programs, resulting in a smaller per customer charge than S.C. No. 2. The same is true for North Shore's S.C. No. 2 relative to S.C. Nos. 3, 4 and 6. NS-PGL Ex. 4.0 at 5.

B. Staff's Position on Rider EOP

1. Appropriate Rate Groups for Cost Recovery

It appears that Section 8-104(c) of the Public Utilities Act ("Act") requires that the utility provide energy efficiency measures for all customers and that all customers are responsible for cost recovery of energy efficiency measures except those customers who are exempt, based on Section 8-104(m) of the Act. If all customers are required to pay for energy efficiency measures, then the issue becomes one of how to charge customers. (Staff Ex. 3.0, pp. 2-3)

Mr. Hendrickson further stated that the Utilities are proposing to charge customers in a manner that includes all customer classes in three rate groups for purposes of energy efficiency programs. The three rate groups are based, generally, on customer size and each of the three rate groups would have a separately determined cost recovery charge. (Staff Ex. 3.0, p. 3)

Staff witness Hendrickson further stated that the rate groups, as defined by Peoples/NS, are appropriate for the recovery of energy efficiency costs and should be approved. (Staff Ex. 3.0, p. 3)

2. Rider Recommendations

Staff witness Dianna Hathhorn made four recommendations to Rider EOA in Staff Ex. 4.0. The Utilities agreed to all four recommendations in discovery responses. The Utilities did not respond further in rebuttal testimony. Therefore, Staff considers these recommendations uncontested. The four recommendations are as follows.

a) Require Testimony in Reconciliation Proceeding

Staff witness Hathhorn recommended the Commission require the Utilities to file testimony regarding the prudence and reasonableness of their costs incurred and recovered during the reconciliation periods being reviewed. The Utilities agreed to this change in their response to Staff Data Request DLH-2.07. (ICC Staff Ex. 4.0, pp. 3-4)

b) Specify Rate of Return as Most Recently Approved by the Commission

Staff witness Hathhorn recommended the Utilities add language to Section C, Definitions, of proposed Rider EOA to specify that the revenue requirement equivalent of the return of and on a capital investment associated with the energy efficiency and/or on-bill financing measures is the rate of return based on the most recent rate of return approved by the Commission. The Utilities agreed that this is their intention in their response to Staff Data Request DLH-2.03. (ICC Staff Ex. 4.0, pp. 4-5)

c) Specify Date When Costs Are Eligible For Recovery

For purposes of clarity regarding the exact date when costs are eligible for recovery under Rider EOA, Staff witness Hathhorn recommended the Utilities include in the tariffs the specific July 10, 2009 effective date of Public Act 96-0033. The Utilities agreed to this change in their supplemental response to Staff Data Request DLH-2.04. (ICC Staff Ex. 4.0, p.5)

d) Revise Rider UEA Reflecting Implementation of Riders EOA and OBF

Staff witness Hathhorn also recommended the Utilities revise Rider UEA to reflect that upon implementation of Riders EOA and OBF, the Rider UEA calculation of adjustments under Rider UEA will be affected, as described in the Utilities' supplemental response to Staff Data Request DLH-2.08 (ICC Staff Ex. 4.0, Attachment A). The Utilities agreed to this change in their supplemental response to Staff Data Request DLH-2.08. (ICC Staff Ex. 4.0, pp.5-6)

3. Cost Recovery Mechanism

The tariff proposed by Peoples/NS collects funds on a per customer basis. Staff recommends that the tariff be changed to collect energy efficiency funds on a per therm basis. A per therm charge is more equitable and provides a price incentive for customers to reduce usage. (Staff Ex. 1.0, p. 7)

A per therm charge is more equitable because higher use customers will pay more than lower use customers. These higher use customers are also more likely to benefit from the programs. A flat charge tends to redistribute wealth from lower use customers towards higher use customers. (*Id.*) Dr. Brightwell illustrates this point by referring to the C&I Retro-Commissioning program proposed by Peoples/NS. In North Shore's territory, the average project cost in Plan Year 1 is about $15,000. Assuming a per customer charge of $5 per month (which is most likely higher than it will be), the average customer would expect to receive a direct benefit from this program every 3000 months or once every 250 years. By changing the tariff to a per therm charge, the higher use customers, who are most likely to benefit from this and similar programs, pay a greater share of the programs. (*Id.*, pp. 7-8)

A typical lower use customer does not stand to reduce his usage as much as a higher usage customer. This means the benefits from upgrading to more efficient furnaces and appliances are not as great for the lower use customer. The costs to purchase appliances or heating systems are largely the same for customers of either usage level. It is more likely that the energy efficient appliances or furnaces are economically justified for the higher use customer and that higher usage customers will take advantage of the programs. Since there is a greater economic incentive for the higher usage customers to take advantage of the program, it is reasonable to charge these customers more than lower usage customers. (*Id.*, p. 8)

Further support for the equity of a per therm charge was provided by the Peoples/NS in responses to Staff Data Requests DAB 3.01-3.12. (See ICC Staff Group Exhibit 2) Mr. Korenchen testified about the rate impacts of a per therm charge. (NS-PGL Ex. 4.0, pp. 7-10) In that testimony, he indicated that the top 20% of Peoples Gas S.C. 1 customers would fund 41% of energy efficiency programs for that service classification. (*Id*., p. 7) However, that top 20% also uses 41% of all therms consumed by Peoples Gas S.C. 1 customers (Utilities' response to Staff Data Request DAB 3.01 – ICC Staff Group Ex. 2). Under the per customer charge, the lowest 50% of users in any rate class would fund 50% of the energy efficiency program.[139] However, the lowest 50% of PGL S.C. 1 customers use only 22% of the total therms (Utilities response to Staff Data Request DAB 3.02 - ICC Staff Group Ex. 2), while 4400 of the customers in this rate class used a total of 16,774 therms or less than 4 therms per customer annually (Utilities response to Staff Data Request DAB 2.01a - ICC Staff Group Ex. 1). The Utilities acknowledge that no measure or program would be cost beneficial for customers with zero or very low usage (Utilities response to Staff DR DAB 2.01b - ICC Staff Group Exhibit 1). However, the per customer charge bills each of these low usage customers the same as a customer that is in the top 20% of users.

There is even greater disparity in usage in the PGL Service Classification No. 2. The top 20% of customers use approximately 78% of all S.C. No 2 therms. (Utilities' response to Staff Data Request DAB 3.03 - ICC Staff Group Ex. 2) The lowest 50% of S.C. 2 customers use approximately 6% of total therms (Utilities' response to Staff Data Request DAB 3.04 - ICC Staff Group Ex. 2). There were 165 customers with combined deliveries of 521 therms, or about 3.2 therms annually per customer. (Utilities' response to Staff Data Request DAB 2.04 - ICC Staff Group Ex. 1) These customers (and all other S.C. No. 2 customers) would pay about $53.76 annually under a per customer charge. Assuming $1 per therm, these customers would pay $3.20 on average for therm usage and $53.76 for energy efficiency. For these customers, the charge to encourage energy efficiency would be about 17 times greater than the charges for their usage.

The Utilities indicate that the high charge for a PGL S.C. No. 2 customer would be $3,266.80 on a per therm basis. (NS-PGL Ex. 4.0, p. 9) Although this seems high, the gas EE law limits the amounts paid by the average retail customer to no more than 2% in an applicable three-year period. On a per therm basis, this means all customers are limited to 2% as a bill impact. Thus, this $3,266.80 represents no more than a 2% price increase for this customer.

A 2% price increase through a per therm charge also provides a price signal that may serve to reduce this customer's bill impact. Dr. Brightwell cited a study that indicated that the short-run and long-run price elasticities for natural gas are -.047 and -

[139] Under a per customer charge, all customers pay an equal charge. Under this scenario, ten percent of customers contribute 10% of the funds, 20% of customers contribute 20% of funds, etc.

.122, respectively. This means that a 1 percent price increase results in a .047% reduction in consumption in the short-run and a .122% price reduction in the long-run. An annual price increase of 2% would be expected to cause a .094% reduction in usage in the first year and a .244% reduction in usage in later years. A reduction of .094% represents nearly half of the reduction required in the first plan year and it is attainable merely by changing the method through which funds are collected. (Staff Ex. 1.0, pp. 9-10)

Mr. Korenchen's rebuttal testimony continues to describe the differences in payment ranges and funds that are collected for various other Peoples Gas Service Classifications and North Shore Gas service classifications. (NS-PGL Ex. 4.0, pp. 8-10) Staff's arguments are similar to those presented above. For brevity, Staff refers the ALJ to the Utilities responses to Staff Data Requests DAB 3.01-3.12. (See ICC Staff Group Ex. 2) The lowest 50% of users in PGL S.C. Nos. 4, 5, 7, and 8 use approximately 19% of total therms in those classes (Utilities' response to DAB 3.06 - See ICC Staff Group Ex. 2). The lowest 50% of customers in NS S.C. No 1 used 30% of total therms in that class (Utilities' response to DAB 3.08 - See ICC Staff Group Ex. 2). One hundred sixteen of these SC 1 customers combined usage was 585 therms (Utilities response to DAB 2.11a - See ICC Staff Group Ex. 1). The lowest 50% of NS S.C. 2 customers combined usage was 5% of all therms in that service classification (Utilities' response to DAB 3.10 - See ICC Staff Group Ex. 2). The lowest 50% of users in NS S.C. Nos. 3, 4, and 6 combined for about 16% of the total therms in those service classifications (Utilities' response to DAB 3.12 - See ICC Staff Group Ex. 2). Although the funds contributed by higher use customers may seem high, these funds represent no more than a 2% price increase and the per therm charge provides a price signal that serves to incent reduced usage.

Mr. Korenchen also indicates that the per therm charge creates an uncertain revenue stream. (NS-PGL Ex. 4.0, p. 11) However, the other electric and gas utilities in Illinois have established energy efficiency tariffs that collect funds on a per therm or per kilowatt hour basis. (Staff Ex. 1.0, p. 10) Peoples and North Shore Gas are the only utilities to submit a proposed tariff that collects funds on a per customer basis.

For the reasons provided above, Staff recommends that the Commission order Peoples/NS to collect these funds on a per therm basis.

C. AG's Position on Rider EOP

The Utilities have proposed to recover the costs of their EEP portfolio through a *non-volumetric per customer charge.*[140] Mr. Mosenthal testified that this is inappropriate because:

1. It results in poor levels of equity among and within customer classes;
2. It requires customers to pay for the EEP costs in a way that is dramatically inconsistent with the customers' opportunities for participation in the EEP, opportunities to capture energy and bill savings, and ability to pay;

[140] *See* NS-PGL Ex. 2.0 at 5-14, NS-PGL Ex. 2.1, and NS-PGL Ex. 2.2.

3. It results in those customers best positioned to capture the largest rebates and other EEP services paying a virtually insignificant share of their gas costs, while those customers likely to benefit least paying relatively exorbitant shares of their gas costs;

4. It is inconsistent with common practice virtually throughout the U.S. for regulated, ratepayer-funded efficiency efforts; and

5. From a policy perspective, it discourages efficiency by minimizing customer costs on the margin and increasing fixed customer charges that can not be avoided.

AG Ex. 1.0 at 18.

In support of the Utilities' per customer proposal, PGL/NS Korenchan states that one objective of his proposal is to "provide equity between and within rate classes."[141] This assertion is based on the claim that a per customer charge will:

> Result in increased equity between and within rate classes. Charges for each rate class reflect the costs budgeted for the programs that customers in each rate class are eligible to participate in and benefit from. Costs are spread evenly among customers within the rate class or classes.[142]

When considering the distinction between customer classes, this statement is true. In other words, only charging residential customers for the costs associated with programs available to them will provide some level of equity between residential versus C&I classes. However, preventing cross-subsidization in the allocation of ratepayer funding by customer class is standard procedure in most jurisdictions, and should occur regardless of whether these charges are per customer or volumetric. AG Ex. 1.0 at 19. For example, the electric EEP funds are recovered on a volumetric basis but still ensure equity between customer classes. All other Illinois utilities subject to the energy efficiency requirements of Sections 8-103 and 8-104 utilize a per therm or per kilowatt charge when recovery program costs.

When considering the C&I customer class, however, there is very large variation in both customer size and gas usage. The Utilities' C&I programs, for the most part, do not distinguish by customer size.[143] Therefore, Mr. Korenchan's assertion that Petitioners' proposal that "Charges for each rate class reflect the costs budgeted for the programs that customers in each rate class are eligible to participate in and benefit from" does not apply at all. On the contrary, a small mom-and-pop business or small office or retail establishment could end up paying a substantial portion of its total bill

[141] NS-PGL Ex. 2.0 at 8.
[142] NS-PGL Ex. 2.0 at 9.
[143] The small business direct install program is limited to smaller customers, however, other programs are available to all C&I customers not choosing to be SDC customers under subsection (m) of the Act.

toward EEP charges — much more than the 2% cap — while a very large industrial customer would pay just a fraction of a percent of its bill. In fact, the Utilities' proposal actually appears to charge the largest customers (service class Nos. 4,5,7 and 8) *only about half as much as smaller customers* (service class No. 2).[144] Presumably, this is based on the Utilities excluding most of the commodity costs of these very large customers in its revenue calculations. This creates a very inequitable system. *Id.* at 19-20.

The way to ensure equity across all customers is with a volumetric charge. This is because opportunities for efficiency savings are generally highly proportional to actual gas usage. The more gas one uses, the more efficiency opportunities they generally have, and the larger the customer's ability to capture larger rebates and other services from the EEP portfolio. Therefore, a volumetric charge correctly charges customers in relative proportion to their opportunities to benefit from the EEP they are funding. *Id.* at 20-21.

In addition, a volumetric charge allows for a consistent per therm charge for everyone within a customer class. This means the percentage surcharges would be the same, imposing a consistent burden on everybody in proportion to the gas they are using, in a fundamentally fair way. Since the Act is clear the General Assembly was concerned about the overall *percentage* rate impact by limiting it to 2%,[145] a volumetric charge is consistent with that desire. Under the Utilities' approach, a small Peoples Gas S.C. No. 2 customer using 1,000 therms per year at an average cost of $0.65 per therm would have a charge of 8.3% of total costs, while a large industrial customer on S.C. No. 4, 5, 7 or 8, using 4 million therms per year at the same average cost, would only pay a charge of 0.0011% of total costs, or proportionally over *seven thousand times less*. This clearly creates an inequitable situation. *Id.* at 21.

In addition, Mr. Mosenthal testified that in his 27 years' experience in the U.S. regulated utility energy efficiency field, he came across only a single jurisdiction where this approach was used, and this was not related to any utility programs. The exception was a small state energy efficiency fund established by the Ohio state energy office, outside of utility regulatory jurisdiction. *Id.*

For all of these reasons, a volumetric surcharge should be adopted by the Commission. In its Order, too, the Commission should clarify that only prudent and reasonable program costs will be recovered through the rider.

D. Commission Analysis and Conclusions

The Commission approves the four modifications to the tariff proposed by Staff noted above. The only other tariff issue is whether to provide for per therm or per customer cost recovery. The Commission finds Staff and the AG's arguments in favor of a per therm cost recovery approach persuasive. The more gas one uses, the more

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[144] For Peoples Gas, SC Nos. 4,5,7 and 8 would pay $2.34/month, while SC No. 2 would pay $4.48/month. For North Shore, the respective values are $2.48/month and $4.33/month. NS-PGL Ex. 2.0 at 14.

[145] 220 ILCS 5/8-104 (d)

efficiency opportunities they generally have, and the larger the customer's ability to capture larger rebates and other services from the EEP portfolio. Therefore, a volumetric charge correctly charges customers in relative proportion to their opportunities to benefit from the EEP they are funding. The Commission approves a per therm cost recovery mechanism for Rider EOA.

VIII. DCEO PLAN

A. North Shore/Peoples Gas' Position

1. On Programs

The Utilities state that they communicated with and supported DCEO throughout the planning process. They provided data to DCEO on the markets it will serve, budgets, goals and inputs for the cost-effectiveness screening analysis. Beginning in April 2010 and lasting throughout the planning process, they conducted in-person meetings and weekly conference calls with DCEO. Based on these meetings, all spending and savings for the low income sector will be DCEO's responsibility. The Utilities state that they have not designed or budgeted for any programs targeting low income customers who pay directly for their own gas space or water heating. NS-PGL Ex. 1.0 at 6.

The Utilities state that, except as to levelized funding and low-income programs, which are addressed later in the Order, the Utilities take no position on DCEO's plan and do not oppose any of the programs described in DCEO's testimony.

2. On Levelized Funding

Mr. Feipel addresses funding for the DCEO programs. DCEO prefers a levelized budget approach. Mr. Feipel also expressed concerns about DCEO being able to meet the low income goals within Integrys' budgets. DCEO Ex. 1.0 at 40-45.

First, the Utilities respond that "Integrys" is not proposing a single plan for its two utilities. North Shore and Peoples Gas will implement separate plans, albeit plans with many common features. This distinction is important because each utility will have a budget that determines "available funding" and each utility as well as DCEO will need to meet distinct targets for each service territory. NS-PGL Ex. 3.0 at 25.

Second, the Utilities are proposing to meet each year's savings requirements, rather than focusing on the Plan Period, and their funding is consistent with this ramping up approach. Mr. Marks states that DCEO's levelized approach would require the Utilities to provide more funding in year one than they are collecting from ratepayers. NS-PGL Ex. 1.0 at 7. The Utilities state that it is unclear from DCEO's testimony if DCEO concurs with the Utilities' definition of "available funding." The Utilities state that, for each Program Year, DCEO is entitled to 25% of the available funds approved by the Commission and recovered through Rider EOA. As used in the proposed rider and Section 8-104(e), available funding per Section 8-104(e) is the funding "associated with energy efficiency programs approved by the Commission." Therefore, when the rider uses the term "available funding," Mr. Korenchan explains that this means that DCEO is entitled (subject to meeting other legal requirements) to receive 25% of amounts recovered from customers under Rider EOA for each of the Utilities. NS-PGL Ex. 2.0

REV at 14. For example, if the Utilities' Plan to achieve each of their goals has a budget of $5.0 million for the first year of the Plan Period, DCEO's budget should be $1.67 million. This would equate to a total budget of $6.67 million, of which $1.67 million or 25% would be for DCEO. NS-PGL Ex. 1.0 at 6-7. If DCEO is proposing to receive more than 25% of the "available funding," this is contrary to Section 8-104.

Third, the Utilities state they would oppose the Commission requiring that they adopt a levelized approach. Their Plan is based on gradually ramping up to meet the goals. NS-PGL Ex. 3.0 at 24.

Fourth, the Utilities state that they would not oppose the Commission opting to accommodate DCEO's preference for a levelized approach limited to the DCEO programs, provided that the Commission gives guidance on cost recovery. NS-PGL Ex. 3.0 at 24. Mr. Korenchan explains that proposed Rider EOA would require at least the following changes, with an attendant increase in the complexity of the rider:

1) DCEO would need to split its budget into categories consistent with Rider EOA's service classification categories. This split is not necessary under the Utilities' proposal because DCEO does not have a separate budget for funding; instead, as prescribed by Section 8-104, DCEO would receive 25% of available funds for energy efficiency collected from customers.

2) Rider EOA would require separate calculations, separate factors and separate reconciliations for DCEO costs and recoveries, adding to the complexity of the rider mechanism. These separate calculations are not necessary under the Utilities' proposal because Rider EOA does not have separate factors for DCEO that would require individual calculations and reconciliations. A change to the methodology for setting DCEO's budget would likely result in new Rider EOA charges for DCEO Residential Service Classification ("S.C.") No. 1, DCEO Residential S.C. No. 2, and DCEO C&I for S.C. Nos. 4, 5, 7 and 8 for Peoples Gas, and 3, 4 and 6 for North Shore.

These changes would also be required with any change in DCEO funding levels from the amounts included in the Utilities' Plans that are based on a percentage of the total annual energy efficiency recoveries through Rider EOA. NS-PGL Ex. 4.0 at 12.

3. Low Income Program Funding

Mr. Feipel expressed concerns about DCEO being able to meet the low income goals within Integrys' budgets. He stated that an alternative to his levelized funding proposals is for Integrys to include the low income proposals in its plan. DCEO Ex. 1.0 at 40-45.

First, as stated above, "Integrys" is not proposing a single plan for its two utilities. This distinction is important in this context because Peoples Gas has a significantly larger proportion of low income customers. NS-PGL Ex. 3.0 at 25.

Second, the Utilities concur with DCEO that it makes sense for DCEO to serve the entire low income market. Splitting responsibility between the Utilities and DCEO would not be efficient. As to Peoples Gas, it is premature to conclude that funding will be inadequate. As Mr. Marks explained, the Utilities acknowledge that the low income market is more expensive to serve, but experience with gas efficiency programs targeting the low income sector suggests that there are significant energy savings opportunities at reasonable costs. This is a not an issue for North Shore. NS-PGL Ex. 3.0 at 25.

B. Staff's Position

Staff does not address these topics in its brief, but it did provide testimony on low income program funding issues affecting DCEO's budget to which DCEO has responded below.

C. AG's Position

The Utilities and DCEO have a disagreement about the appropriate budgets over the three years of the plan. The Utilities have proposed a ramp up of EE spending that closely follows the statutory goals in each year. As a result, providing DCEO funds based strictly on its share of 25% of total cumulative spending results in the transfer of approximately $9.8 million to DCEO for its proposed programs. AG Ex. 1.0 at 54. DCEO's budgetary ramp up per year — based on strictly following the Utilities' proposed budgets — is highlighted in the following table:

DCEO budget from:	PY 1	PY2	PY3	Cumulative
Peoples Gas	$ 1,905,640	$ 2,747,703	$ 3,598,060	$ 8,251,403
North Shore Gas	$ 333,404	$ 574,176	$ 689,238	$ 1,596,818
Total	**$ 2,239,044**	**$ 3,321,879**	**$ 4,287,298**	**$ 9,848,221**

Id.

DCEO is proposing a levelized budget of the three-year period, rather than a ramp up in funding, as proposed by the Utilities. This would result in a higher than 25% allocation in the first year of the plan cycle, but less than 25% in the last year. DCEO proposes a levelized budgetary allotment because it claims, according to the Utilities, that it believes it can achieve greater savings in PY1, effectively achieving roughly PY2 goals in each year of the plan.[146] The Utilities are concerned about DCEO's proposal because it would require Peoples Gas and North Shore to provide DCEO with more funding in year one than they would be collecting from ratepayers.

In addition, NS-PGL witness Marks indicates that DCEO does not believe 25% of the overall budget will be sufficient to meet is target of 20% of portfolio savings.[147] DCEO's underachievement is primarily due to the perceived higher cost of saved energy in the low income market sector. The Utilities assert that it is too early in the process to determine if DCEO funding is insufficient to achieve its goals.[148]

While the Utilities' plans of a more gradual ramp up — consistent with the annual statutory goals — are appropriate for PGL/NS to provide the time needed to build

[146] NS-PGL Ex. 1.0 at 7.
[147] NS-PGL Ex. 1.0 at 7.
[148] NS-PGL Ex. 1.0 at 7 (Marks).

capability, start new programs, and ramp up over time to better position it for achievement of PY4 savings goals, Mr. Mosenthal testified that he did not believe it would be appropriate for the Utilities to deny DCEO the necessary funding to fully support projects in which customers are ready and willing to install measures. *Id.* at 55.

He suggested that the Commission allow the 25% of budget rule to be managed on a cumulative three-year basis, and not specifically mandate that DCEO spending must equal 25% in each program year. Mandating that spending match these targets each year creates an unnecessary and potentially burdensome system where controlling whether projects close in December or January could have major impacts on DCEO program delivery – impacts that at least financially would be out of DCEO's control. *Id.*

Presumably, the Utilities, DCEO and the ICC can establish an appropriate cost recovery mechanism level to support the planned expenditures of both the Utilities and DCEO for each year, avoiding any need for Peoples Gas and North Shore to front substantial funds to DCEO that they have not yet collected. In the event DCEO is unable to spend all the funds provided in a given year, such funds can always be carried over to the following year within the three-year time frame. This approach ensures DCEO won't need to walk away from potential cost-effective savings opportunities, while at the same time smoothing out the rate impacts to customers by somewhat leveling the three years' worth of contributions. *Id.*

As to the issue of whether DCEO can achieve 20% of the savings with 25% of the overall funds, Mr. Mosenthal concurred with the Utilities that there is sufficient time to monitor DCEO progress (especially since it believes it can overachieve in the first year) to reconsider this issue after DCEO has had more experience with the gas portfolio.

D. DCEO POSITION

Even though annual gas targets are included, the natural gas planning process outlined in the statute is done on a three year, not an annual, basis. See 220 ILCS 5/8-104 (c), (d) and (f). As a result of the three year nature of the gas planning process, DCEO is treating its natural gas savings goals and budgets as three year, cumulative objectives. Each of DCEO's annual budgets are one-third (1/3) of the total three year budget needed to meet its 3 year cumulative goals. As the relevant gas utility, North Shore and Peoples would collect the needed funds each year, as reflected in DCEO Exhibit 1.4. These funds would then be made available to DCEO each year, pursuant to the obligation process as outlined in Section 8-104(e). DCEO's plan falls well within the rate cap of Section 8-104 on an annual basis, and in no year does its budget plus the North Shore and Peoples budgets exceed the statutory rate cap. DCEO can meet its 20% therms savings goal, its other statutory goals, and the additional statutory requirements it has taken on for the utilities without needing to spend up to the rate cap.

The only statutory limitation on funding is the rate cap. Moreover, as stated in Section 8-104(d), the rate cap is applied over the entire 3 year reporting period:

> Notwithstanding the requirements of subsection (c) of this Section, a natural gas utility shall limit the amount of energy efficiency implemented *in any 3‑year reporting period* established by subsection (f) of Section 8‑104 of this Act, by an amount necessary to limit the estimated average increase in the amounts paid by retail customers in connection with natural gas service to no more than 2% *in the applicable 3‑year reporting period*."

220 ILCS 5/8-104(d) (emphasis added).

This language is in direct contrast to the requirements of the electric portfolio found in Section 8-103:

Notwithstanding the requirements of subsections (b) and (c) of this Section, an electric utility shall reduce the amount of energy efficiency and demand‑response measures implemented *in any single year* by an amount necessary to limit the estimated average increase in the amounts paid by retail customers in connection with electric service due to the cost of those measures to:

> 1. in 2008, no more than 0.5% of the amount paid per kilowatt hour by those customers *during the year ending* May 31, 2007…

220 ILCS 5/8-103(d) (emphasis added).

The three year aggregate of DCEO's plan, plus North Shore's and Peoples' relevant three year plans, are each below the relevant statutory three year rate cap.

1. DCEO Levelized Budget

North Shore and Peoples contend that a ramped budget is preferable for implementation of the gas efficiency portfolio and associated programs for the utilities. In his testimony, the utilities' witness Michael Marks states that "The Utilities would oppose the Commission requiring that they adopt a levelized approach. Their Plan is based on gradually ramping up to meet the goals. However, the Utilities would not oppose the Commission opting to accommodate DCEO's preference for a levelized approach limited to the DCEO programs, provided that the Commission gives guidance on cost recovery." NS-PGL Exhibit 3.0, p. 24. DCEO concurs that a ramped budget makes sense for North Shore and Peoples and maintains its position that a levelized budget is prudent for DCEO. Attorney General witness Mosenthal further agrees with this approach, stating that "I therefore suggest that the Commission allow the 25% of budget rule to be managed on a cumulative three-year basis, and not specifically mandate that DCEO spending must equal 25% in each program."

The Utilities' and DCEO's plans are three year plans and not annual. While correct that in year 1 DCEO's budget exceeds 25% of the utilities' budget and in year 3 will be less than 25% of utilities' budget, these individual years do not matter. The Utilities and the Attorney General's Office agree, this approach is the most effective for DCEO, and it is consistent with the statute. Therefore, DCEO submits that the

Commission should approve DCEO's budgets as presented and order the Utilities to collect the relevant funding through its tariffs.

2. DCEO Budget Amount

Under the Public Utilities Act, DCEO's plan: (1) must achieve 20% of the gas savings; (2) must provide 40% of its budget (10% overall portfolio) for municipalities, municipal corporations, K-12 schools and community colleges; and (3) must integrate its natural gas and electric programs unless infeasible. 220 ILCS 5/8-104(e). The statute also suggests that DCEO provide market transformation assistance to municipalities. 220 ILCS 5/8-104(e). That is all. DCEO could have filed a plan that met only these requirements. However, DCEO also agreed to take on the other, more difficult, less cost effective sectors as stated earlier because it is in the best position to administer these programs. As DCEO has explained, the low income sector, and to a lesser extent the public sector, require more dollars saved per therm compared to standard residential and commercial programs. This is exacerbated by the argument that DCEO should be arbitrarily constrained by 25% of the budget proposed by the utilities and not 25% of the statutory rate cap. As outlined in the previous section, the rate cap is the only statutory limit on spending.

Attorney General witness Mosenthal opines that "As to the issue of whether DCEO can achieve 20% of the savings with 25% of the overall funds, I agree with the Utilities that there is sufficient time to monitor DCEO progress (especially since it believes it can overachieve in the first year) to reconsider this issue after DCEO has had more experience with the gas portfolio." AG Exhibit 1.0, p.55. As explained in more detail below, this statement raises two issues: that DCEO can meet its statutory obligations using only 25% of the utilities plans and that DCEO can successfully manage its programs without final budget approval now.

First, DCEO has never disputed that it can meet DCEO's statutory requirements and 20% of the therms savings goal with a budget limited to 25% of the utilities plans. However, DCEO does dispute that it can meet these requirements in addition to those it has taken on voluntarily with a budget limited to 25% of the utilities' plans. As DCEO noted in its testimony, because North Shore and Peoples are spending less per therm saved than the other utilities, artificially holding DCEO to 25% of the North Shore and Peoples budgets would leave DCEO with insufficient funding to achieve 20% of the savings *plus* meet the requirements it has taken on voluntarily in the utilities' territories (low income and building codes and standards). DCEO Exhibit 1.0, p. 44.

If the Commission arbitrarily caps DCEO at 25% of the utilities plan level instead of 25% of the rate cap, then, in order to meet its statutory requirements, DCEO would focus on its public sector programs in order to make sure it meets the Department's 20% savings goal. The result would be little to no market transformation activities and low income programs in the North Shore and Peoples territory. The low income and building codes and standards statutory requirements would not be met for the utilities. Conversely, if the Department does not include the low income programs and other statutory requirements in its plan, then the utilities would have to incorporate them into its own – thereby increasing the utilities' budgets. As the utilities point out, "The Utilities concur with DCEO that it makes sense for DCEO to serve the entire low income market." NS-PGL Ex. 3.0, p. 25.

Because DCEO has also been given the low income sector spending requirements and the building codes and standards mandate and has the market transformation goal, this requires additional funding in the utilities territories above strictly 25% of what the utilities plan to spend on their efficiency programs. This spending is not included to exceed the targets or merely because it is a good thing to do – rather it is necessary to meet all of the statutory requirements. If DCEO were able to meet these requirements with less funding then its plan would have reflected this. As noted above, this is a three year efficiency plan and DCEO cannot adopt a wait and see approach to its programs as some suggest in this proceeding. DCEO's plan presents the budget amounts necessary to meet all of its statutory goals plus the additional low income requirement.

Second, Attorney General Witness Mosenthal's wait and see approach is not workable. Many of its integrated gas and electric programs will be implemented through multi-year contracts that are executed in June 2011. Lack of budget certainty would provide no ability to plan and manage DCEO's programs over the three years. Revisiting budgets would greatly impede DCEO's programs.

The Department's budget plus the planned expenditures of the utilities still fall well under the statutory rate impact cap. Thus, the DCEO plan is consistent with the statute, is acceptable and prudent. Therefore, DCEO submits that the Commission should approve DCEO's budgets as presented and order the utilities to collect the relevant funding through its tariffs.

3. DCEO Position on Low Income Issues

ICC Staff witness David Brightwell raises three issues with DCEO's plan, relating to DCEO's low income programs, its Building Code Compliance program, and serving Federal facilities. DCEO disagrees with ICC Staff's analysis.

a) Low Income Programs and Lost Opportunities

Staff witness Brightwell states that "Although initially this may appear to be a good use of funds, there are cases where an alternative measure that saves more energy than the baseline measure but less energy than the most efficient measure is actually preferable from both a net benefit and an energy savings perspective." ICC Staff Exhibit 1.0, p. 10. While staff's mathematical analysis is unique, staff's recommended procedure for determining what measures are included in its low income energy efficiency programs would not result in the most prudent use of public funds. This analysis discounts the social tendencies of low income residents.

As discussed by DCEO witness Knight in DCEO Exhibit 5.0, ensuring that the most efficient measures are installed all at once is critical given specific aspects related to the low income sector. Knight stated that:

"One societal benefit is related to the fact that ratepayers and/or taxpayers are currently subsidizing the energy bills of many low income households. … Generally, there is only one opportunity to get into these homes to improve their energy efficiency. Therefore, to seize this opportunity and minimize the long-term subsidy of energy bills, low income energy efficiency programs are designed to achieve the maximum amount of energy efficiency within the fiscal constraints of the programs." DCEO Ex. 5.0, p. 5.

Low income residents are very protective of their private lives and tend to only allow outside groups into their homes once. Because low income energy bills are subsidized by rate payers and/or taxpayers, maximizing energy efficiency in those homes that receive these subsidies directly reduces or eliminates the need for society to cover these costs. Further, in homes not covered by these subsidies, even a slight decrease in energy bills, for example resulting from the difference between a 95 versus a 92 AFUE furnace, has a tremendous impact on the disposable income of low income consumers that can be used for essentials like food, medicine, etc.

The Evaluation Measurement and Verification contractors noted in their evaluations of DCEO's low income energy assistance programs that DCEO followed best practices for designing low income programs. The programs have been designed by a consultant (Mr. Paul Knight) with more than 30 years experience with low income programs and staff with more than 20 years experience.

DCEO must be able to meet its statutory gas savings goal and contribute meaningfully to the electric savings goal while still following best practices in serving its relevant sectors. DCEO certainly considers the energy savings gained per dollar expended because this ratio is critical to meeting its energy savings targets. This ability has been factored into DCEO's analysis along with balancing its important public policy goals like those explained above. The procedure described by the staff to identify cost effective measures was used by DCEO in developing its plan. Applying this approach strictly with no exceptions is unnecessary and overly limited.

b) Building Energy Code Compliance

ICC staff opines that the energy savings from DCEO's Building Energy Code Compliance Program are not incremental savings and should not be paid for through ratepayer funding. ICC Staff Exhibit 1.0, p. 15. The staff argues that since the American Recovery and Reinvestment Act ("ARRA") already requires DCEO to improve compliance with energy codes and that the Energy Efficiency Buildings Act requires DCEO to provide training on building codes, that ratepayers under DCEO's Energy Efficiency Portfolio should not pay for such programs. However, the existence of such mandates does not mean that any funding has been specifically provided for them.

The EEP statute requires "specific proposals to implement new building and appliance standards". 220ILCS 5/8-103(f)(2); and 220 ILCS 5/8-104(f)(2). Therefore, it is clear that the General Assembly intended for ratepayer funds to be used for such programs. It is in part because of this language and the potential availability of state funds that the Governor was able to sign a letter agreement with the US Department of Energy that the state would work towards the goal of improving compliance with energy efficiency building codes. The U.S. Department of Energy guidance on the ARRA programs has specific language that the funding is to "supplement not supplant" state funding for energy programs. DCEO has worked to supplement the funds it has been using from the EEP law for building code training with federal funds. Specifically, DCEO has applied for and received a grant to measure current compliance levels with energy efficient building codes and DCEO has encouraged cities and counties to use Energy Efficiency and Conservation Block Grant ("EECBG") funds for building code related activities. DCEO plans to continue using EEP funds to support its building code training programs as part of its "market transformation" programs. These programs will result in incremental and measurable energy savings that can be counted as discreet to the EEP funding.

c) Federal Facilities

ICC staff takes the position that federal facilities should not receive ratepayer funds. ICC Staff Exhibit 1.0, p. 15. The staff refers to an executive order signed by President Obama that requires construction and renovation of federal buildings to comply with "Guiding Principles for Federal Leadership in High Performance and Sustainable Buildings" and to aim to "reduce the energy cost budget by 20% below pre-renovations 2003 baseline".

The State of Illinois has similar mandates. The Agency Energy Efficiency Act of 2008 mandates the State to reduce energy use in State facilities by 10% within 10 years. Executive Order #11 sets an ambitious objective of reducing electricity and natural gas consumption in State-owned facilities by 25% by 2025, among other provisions. The City of Chicago adopted a Climate Action Plan that commits the city to reducing energy use in buildings by 30%. Most cities in Illinois are either working towards or have already adopted similar commitments. The staff's argument, taken to its logical conclusion, would prohibit DCEO from providing funding to any units of government that are setting ambitious energy efficiency goals. Again, as argued above, just because a mandate exists to improve efficiency does not mean that funding is available and that the mandate is actually being met. DCEO has to have the ability to provide funding to any unit of government that is seeking to improve its energy efficiency, in order for these entities to actually implement energy efficiency measures given the realities of public sector budget constraints and for its Public Sector Energy Efficiency programs to be effective.

E. Commission Analysis and Conclusions

The Commission finds that Section 8-104 permits the Utilities to meet the requires savings on a year-by-year basis, rather than a triennial planning period basis. It is their choice which approach to take. The Commission will not order them to adopt a levelized approach, nor to make the tariff changes described by witness Korenchan. The tariff complexity to accommodate a ramped up approach by the Utilities and a levelized approach by DCEO would make the reconciliation process under Rider EOA unnecessarily complicated.

The Commission also finds that it is reasonable for DCEO to handle all low income programs. At this time, the record does not support concluding that the funding available to DCEO will be inadequate to meet requirements for Peoples Gas' customers. There appears to be no issue for North Shore. If substantial plan changes are required, consistent with our findings above, those changes should be filed with the Commission.

The Commission rejects DCEO's argument that the Commission has limited authority over DCEO's portion of the plan. It is clear from the language of the statute that the Commission was given authority to review the entirety of the Plans, including the DCEO portion, and to approve the Riders to collect the funds to pay for these plans. All energy efficiency measures must be approved by the Commission, regardless of whether they are implemented by the utility or the DCEO.

The Commission is cognizant of Staff's concerns regarding the independence of the evaluation, however DCEO is a sister agency required to use the same State of Illinois procurement process for contracts of this kind. The Commission can neither modify this procurement process, nor add additional requirements. As a result, the Commission declines to adopt Staff's recommendations for DCEO.

IX. UNCONTESTED STATUTORY REQUIREMENTS

A. North Shore/Peoples Gas' Position

1. Section 8-104(f)(2)

Section 8-104(f)(2) states that the utility shall: "Present proposals to implement new building and appliance standards that have been placed into effect." The Plan meets this requirement. The Utilities designed their programs using applicable building codes and appliance standards to determine eligibility of certain measures and services for the inclusion of the Utilities' programs. If changes occur in new building and appliance standards during Plan Period, the Utilities will make program design changes to accommodate those new standards. NS-PGL Ex. 1.0 at 12. Neither Staff nor any intervener testimony contested this issue. Staff witness Dr. David Brightwell stated that he reviewed five[149] of the eight filing requirements and believes that the company's plan is substantially consistent with the filing requirements. ICC Staff Ex. 1.0 at 2.

2. Section 8-104(f)(3)

Section 8-104(f)(3) states that the utility shall: "Present estimates of the total amount paid for gas service expressed on a per therm basis associated with the proposed portfolio of measures designed to meet the requirements that are identified in subsection (c) of this Section, as modified by subsection (d) of this Section." The Plan meets this requirement. The Utilities estimated savings over the Plan Period to cost \$1.66 per therm for North Shore and \$2.00 per therm for Peoples Gas. The total cost for the Plan Period is \$4.2 million for North Shore and \$22.5 million for Peoples Gas. These values include the cost for the independent evaluation, measurement and verification contractor. They do not include funding for on-bill financing or the DCEO's

[149] He stated that Mr. Zuraski reviewed subsection (f)(1), subsection (f)(6) does not apply to the Utilities, and he had comments on subsection (f)(8). ICC Staff Ex. 1.0 at 2.

share of the budget. NS-PGL Ex. 1.0 at 12. Neither Staff nor any intervener testimony contested these calculations. Dr. Brightwell stated that he reviewed five of the eight filing requirements and believes that the company's plan is substantially consistent with the filing requirements. ICC Staff Ex. 1.0 at 2.

B. Commission Analysis and Conclusions

The Commission finds that the Utilities have met the statutory requirements.

X. MISCELLANEOUS ISSUES - CONSORTIUM TESTIMONY

A. North Shore/Peoples Gas' Position

Mr. Bourke states that it "would be constructive for the Commission to direct North Shore to consult with the Consortium in a meaningful, substantive manner on energy efficiency and related matters." Mr. Bourke also testified at some length about a "Model Franchise Agreement," and he claims that there is "clear interplay" between energy efficiency and the Consortium's efforts to establish this model agreement. Consortium Ex. 1.0 at 12.

The Utilities state that, if Mr. Bourke's issue is that he is dissatisfied with the extent to which North Shore has met with the Consortium about its model agreement (Consortium Ex. 1.0 at 9), that has no relevance to this proceeding. If Mr. Bourke's issue is that North Shore did not meet with the Consortium about energy efficiency, that is not a deficiency in the Plan.

Mr. Marks explains that the Utilities worked extensively with DCEO and various stakeholders on the development of their Plan. Throughout Plan development, the Utilities engaged stakeholders to obtain input on issues that were important to each stakeholder. They met with Commission Staff, the AG, CUB, the City and ELPC. They considered all stakeholder input in the Plan preparation and incorporated stakeholder input that did not deviate from the Utilities' overarching objectives. Mr. Marks also states that the Utilities worked closely with ComEd throughout the Plan development. The Utilities also worked with the other Illinois gas utilities subject to Section 8-104 (Ameren and Nicor) to provide consistency in program design where possible. Mr. Marks states that the Utilities communicated and supported DCEO throughout the planning process. They provided data to DCEO on the markets it will serve, budgets, goals and inputs for the cost-effectiveness screening analysis. In-person meetings and weekly conference calls were conducted beginning in April 2010 and lasting throughout the planning process with DCEO. NS-PGL Ex. 1.0 at 3-4, 6-8.

The Utilities state that Mr. Bourke seems concerned that North Shore did not consult with the Consortium regarding the Plan. Consortium Ex. 1.0 at 10. Mr. Marks states that the DCEO witnesses, particularly Mr. Feipel, testified DCEO is managing the programs to achieve the statutory requirements applicable to local governments and municipalities. The Utilities' Plan does not address efficiency programs for municipalities for this reason. NS-PGL Ex. 4.0 at 26. The Utilities note that Mr. Bourke states that DCEO contacted the Consortium subsequent to becoming aware of its existence when it filed testimony in Northern Illinois Gas Company d/b/a Nicor Gas Company's Section 8-104 proceeding. Consortium Ex. 1.0 at 11. DCEO is the appropriate party to work with municipal governments, and it seems that DCEO is now aware of the Consortium's interest in this matter and is talking with the Consortium.

The Utilities state that the relevance of this proceeding to the model agreement is unclear. Mr. Marks states that, based on Mr. Bourke's description of franchise agreements, it appears that the Consortium's model agreement addresses much more than energy efficiency. NS-PGL Ex. 4.0 at 26. The Utilities note that Mr. Bourke did not include a copy of the proposed model agreement with his testimony, so what, if any, relevance it has to the Commission's decision about whether the Utilities' Plan is compliant with the Act is not apparent from the record. The Utilities state that Mr. Bourke addressed none of the requirements in Section 8-104(f). Mr. Bourke does not claim that the Utilities' Plan falls short of any of the law's requirements, beyond, perhaps, claiming that the requirement that North Shore and DCEO coordinate in the development of the Plan was lacking because North Shore did not speak to the Consortium about its Plan. Consortium Ex. 1.0 at 10. The Utilities state that, assuming, *arguendo*, that the Consortium wished to discuss the Plan and not its model agreement proposal, the fact that North Shore did not consult with the Consortium about the Plan it filed is not a deficiency in the Plan and is not contrary to Section 8-104.

B. The Consortium Position

North Shore witness Mr. Marks confirmed on cross-examination that North Shore made no effort to consult with the Consortium regarding its EEP. Mr. Marks also admitted on cross-examination that even though the Act requires North Shore to consult with DCEO, North Shore never even suggested to DECO that it should consult with the Consortium. The Consortium finds North Shore's failure to consult with the Consortium is surprising and disappointing.

The Consortium's testimony does not delve into all the aspects of the Consortium's draft Model Franchise Agreement. Instead, it describes the aspects of the draft Model Franchise Agreement are directly related to energy efficiency issues.

Mr. Bourke explained that energy efficiency items are not currently covered in North Shore's form franchise agreement, but that they should be addressed in a Model Franchise Agreement. He summarized a recent project undertaken by Region 5 of the U.S. Environmental Protection Agency ("USEPA") (which covers Illinois and several other Midwestern states), to evaluate "opportunities to improve the way that municipal gas and electric utility franchise agreements are structured so that they are more conducive to energy efficiency investments." USEPA recognized the value not only of the Consortium's attempt to build energy efficiency provisions into a Model Franchise Agreement, but also the value of negotiating collectively rather than individually with North Shore.

Mr. Bourke further explained that the Consortium has met with North Shore, however North Shore has been hesitant to discuss franchise agreement issues in substantive detail and has not yet fully engaged in a productive negotiation with the Consortium. (*See id.* at 9:180-84.)

Instead of embracing the Consortium's proposal for cooperation, North Shore has stated that DCEO has responsibility for the portion of the EEP that relates to municipalities; and the Consortium's Model Franchise Agreement addresses "much more than energy efficiency." (NS-PGL Ex. 3.0 at 26:578-83.) The Consortium disagrees with these arguments.

North Shore has overall responsibility for the EEP, including the portion of the EEP that relates to municipalities. North Shore's failure to mention the Consortium to DCEO over the weekly meetings that North Shore has had with DCEO since April of 2010 demonstrates that North Shore has not engaged in good faith efforts to collaborate with stakeholders.

Franchise agreements provide an avenue to achieve or surpass the statutory energy efficiency requirements under Section 8-104, so it is entirely appropriate that they be considered by the Commission as one of the many avenues that should be used to improve energy efficiency in Illinois as required by statute, regardless of whether the franchise agreement also covers non-energy efficiency items.

The fact that those measures could be implemented through a Model Franchise Agreement that incidentally also addresses other issues does not *disqualify* them from this proceeding as North Shore argues. The United States Environmental Protection Agency specifically found that substantive energy efficiency improvement can and should be implemented through franchise agreements. The Commission should consider the use of municipal franchise agreements as an avenue to implement energy efficiency. Given North Shore's intransigence, the Commission should take steps to direct North Shore to consult with the Consortium.

C. Commission Analysis and Conclusions

The Consortium raised no issues about the Utilities' compliance with Section 8-104. The Utilities coordinated with DCEO, as required by the law. They also chose to meet with Staff and many stakeholders. That they did not meet with the Consortium's members is not a flaw in the Plan. Moreover, the Commission finds that the model franchise agreement has at best tangential relevance to this proceeding. The DCEO is encouraged to work with the Consortium to fulfill its obligations to municipalities.

XI. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record and being fully advised in the premises, is of the opinion and finds that:

(1) North Shore Gas Company is an Illinois corporation engaged in the distribution of natural gas to the public in the State of Illinois and, as such, is a public utility within the meaning of the Public Utilities Act;

(2) The Peoples Gas Light and Coke Company is an Illinois corporation engaged in the distribution of natural gas to the public in the State of Illinois and, as such, is a public utility within the meaning of the Public Utilities Act;

(3) the Commission has jurisdiction over North Shore Gas Company and The Peoples Gas Light and Coke Company and of the subject matter of this proceeding;

(4) the recitals of fact and the conclusions reached in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact;

(5) all of the findings and conclusions of this Order describing or defining the parameters of evaluation, measurement and verification ("EM&V") of the Utilities Energy Efficiency Plans are supported by the record;

(6) Rider EOA, as modified by the suggestions of Staff noted in this Order and incorporating a per therm cost recovery mechanism, is just and reasonable;

(7) funding that ramps up to meet each year's goals, rather than a levelized funding approach, is appropriate and allowed under Section 8-104;

(8) the savings levels calculations that exclude deliveries to large volume transportation customers are inconsistent with Section 8-104, Staff's method of calculating spending and savings goals are hereby adopted;

(9) the Utilities shall participate in an advisory SAG so that consumer and governmental shareholders can collaborate with the Utilities relating to their energy efficiency programs; the gas SAG should be structured to facilitate coordination with the electric SAG already in existence;

(10) proposals that the Utilities spend more than is required to meet the savings requirements for the first three-year plan period are beyond the requirements of Section 8-104;

(11) the Consortium's requests related to franchise agreements are beyond the scope of this proceeding; and

(12) all motions, petitions, objections or other matters in this proceeding which remain unresolved should be disposed of consistent with the findings and conclusions of this Order.

IT IS THEREFORE ORDERED that the Petition filed by North Shore Gas Company and The Peoples Gas Light and Coke Company requesting approval of their Energy Efficiency and Demand Response Plans and DCEO's 2011-2013 Energy Efficiency and Demand Response budget filed in compliance with Section 8-104 of the Act is conditionally approved, subject to the Utilities filing a compliance filing that incorporates and is consistent with the findings and conclusions contained in this Order;

IT IS FURTHER ORDERED that North Shore Gas Company and The Peoples Gas Light and Coke Company are authorized and directed to file within 30 days of the date of this Order, revised energy efficiency plans pursuant to Section 8-104 of the Act which contain terms and provisions consistent with and reflective of the findings and conclusions of this Order;

IT IS FURTHER ORDERED that the gas utility stakeholder advisory group to be formed in connection with Section 8-104 shall have the powers and responsibilities described in the conclusions of this Order relative to North Shore's and Peoples Gas' implementation of their obligations under Section 8-104;

IT IS FURTHER ORDERED that Rider EOA, as modified by suggestions from Staff and including a per therm recovery mechanism, is approved;

IT IS FURTHER ORDERED that funding that ramps up to meet each year's goals, rather than a levelized funding approach, is appropriate and allowed under Section 8-104 and is approved for North Shore and Peoples Gas;

IT IS FURTHER ORDERED that the savings levels based on retail customer deliveries that include deliveries to large volume transportation customers is approved as consistent with Section 8-104 of the Act;

IT IS FURTHER ORDERED the rate impact budget calculation properly includes large volume transportation customers;

IT IS FURTHER ORDERED that the Utilities need not spend more than is required to meet the savings requirements for the first three-year plan period;

IT IS FURTHER ORDERED that the Consortium's requests related to franchise agreements are beyond the scope of this proceeding; and

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

DATED:	January 20, 2011
BRIEFS ON EXCEPTIONS DUE:	February 3, 2011

Terrance Hilliard
Administrative Law Judge